Review of New Brunswick Power's 2018/2019 Rate Case Application

In the Matter of the New Brunswick Power Corporation

and Section 103(1) of the Electricity Act

Matter No. 375

Prepared for the New Brunswick Energy and Utilities Board Staff

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EXECUTIVE SUMMARY

Purpose

The New Brunswick Energy and Utilities Board Staff (EUB Staff) commissioned Synapse Energy Economics (Synapse) to review the 2018/2019 General Rate Case application recently filed by the New Brunswick Power Corporation (NB Power or the Company). Our task was to review, critique, and make recommendations on the issues of revenue requirements, the rate adjustment mechanism (RAM), the 2017 integrated resource plan (IRP), and the Energy Smart program—with an emphasis on the demand-side resources and advanced metering infrastructure (AMI) elements within that program.

Revenue Requirements

NB Power's rate request is primarily driven by (a) its revenue requirements, (b) the goal of reducing debt, and (c) the goal of keeping rates low. Reducing costs should be a top priority for the Company and the Board, as this will help with both the goals of reducing debt and keeping rates low.

However, given NB Power's ability to increase rates each year, it faces relatively little financial pressure to reduce costs. In addition, the absence of private equity shareholders limits the Board's ability to disallow cost over-runs or imprudently incurred costs, or to apply financial incentives through performance-based ratemaking (PBR).

We recommend that the Board use regulatory guidance and pressure to encourage, induce, or incentivize the Company to reduce costs. The Board can provide regulatory guidance by approving (or disapproving) specific projects or investments, especially innovative projects such as Smart Habits or AMI. The Board can also provide guidance by signaling to the Company how to prioritize investments, how to optimize resources, how to balance short-term versus long-term interests, and how to balance the goals of reducing debt and maintaining low rates.

The Board can provide regulatory pressure through detailed review and oversight of NB Power's proposed budgets and revenue requirement requests. The Board's oversight should include a Rate Case Performance Report that includes enhanced performance metrics and public reporting requirements specifically designed to inform the Board, the NB Power Board of Directors, legislators, customers, and other key stakeholders about the Company's efforts to control costs. This should also include increased Board oversight of the Integrated Resource Plan (IRP) to assist the Company in optimizing its resources and minimizing its costs. And this should include increased Board oversight of the Energy Smart program to assist NB Power in successfully planning for and implementing all cost-effective distributed energy resources (DERs).

Rate Adjustment Mechanism

The Company's proposed RAM offers the advantage of helping NB Power to meet its debt reduction goals. Unrecovered costs in any single year result in a reduction in net earnings, an increase in debt, and a deferral of the date by which the Company meets its 80 percent debt target.

On the other hand, the proposed RAM has several disadvantages. It would result in greater rate increases, making it difficult to meet the statutory goal of maintaining low rates. It would also: (a) reduce the Company's incentive to reduce the magnitude of extraordinary costs, (b) reduce the transparency of rate adjustments and impacts, and (c) generally make the Company less accountable for costs recovered through the RAM.

We conclude that the disadvantages of the proposed RAM outweigh the advantages, and therefore we recommend that the Board reject the Company's proposed RAM at this time. Our conclusion is partly based on a slight preference for the goal of maintaining low rates over the goal of meeting the 80 percent debt target.

If the Board decides to allow some form of RAM, either in this rate case or in the future, it should do so only after certain conditions are met. These include: (a) NB Power demonstrates that the proposed RAM complies with the interim international accounting reporting standard (IFRS); (b) the Board establishes a Rate Case Performance Report to encourage NB Power to reduce costs; (c) the Company agrees to make any potential RAM rate increases fully transparent, both in rate cases and 10-Year Plan forecasts; (c) the Company agrees to consider the RAM rate increases when achieving the statutory goal of maintaining low rates; and (d) the Board establishes criteria for how to define extraordinary expenses and those that are outside NB Power's control.

2017 Integrated Resource Plan

A sound IRP can help the Company to reduce costs by optimizing the mix of supply-side resources, identifying the potential for distributed energy resources, deferring or avoiding the need for new infrastructure, reducing energy costs, and minimizing the cost of meeting greenhouse gas (GHG) constraints.

The NB Power 2017 IRP suffers from several important limitations. It does not include the cost of meeting GHG constraints in the reference case, even though new GHG constraints are widely expected to be applied in the near term. The 2017 IRP does not optimize, or even explore, the full potential for energy efficiency and demand response resources. This becomes particularly problematic with the introduction of GHG constraints, which would call for a much higher amount of cost-effective energy efficiency and demand response resources to keep costs down. The 2017 IRP also does not account for the potential benefits of deferring or avoiding transmission and distribution costs as a result of distributed energy resources. Taken together, these limitations result in the IRP substantially understating the potential for energy efficiency and demand response resources to reduce electricity system costs.

We recommend that the Board direct the Company to submit a revised IRP by the next rate case, because the 2017 IRP does not provide a realistic forecast of GHG constraints and does not provide an optimization of supply-side and demand-side resources; thus it does not provide some key information that should be used in this rate case. The revised IRP should also address the other limitations identified in this report.

In addition, we recommend that the Board establish guidelines regarding the development, filing, and implementation of future IRPs. Experience in other jurisdictions indicates that clear regulatory guidance is necessary to ensure effective, successful IRP practices.

Smart Habits

In general, the NB Power energy efficiency programs are well designed and are likely to achieve a reasonable level of efficiency savings, given that they are still in the early stages of development. Further, there is clearly considerable potential to continue to expand these programs after the three-year period, as indicated by the Company's IRP analysis (despite the IRP's limitations). There is also a significant need to continue to expand these efficiency programs over time, in light of the pressure on the Company to reduce costs, reduce debt, and maintain low electricity rates.

We recommend that the Board approve the energy efficiency programs, budgets, and savings targets proposed by the Company for the 2018/2019 year. We further recommend that the Board direct NB Power to file in its next rate case a revised DSM plan that addresses the deficiencies identified in this report, particularly regarding program designs and evaluation plans that were not included in the current DSM Plan.

We recommend that the Board reject the demand response programs, budgets, and savings targets for the 2018/2019 year, because the program designs are not sufficiently developed and the proposed programs are not expected to be cost-effective even by the Company's analysis. We further recommend that the Board direct the Company to include in the revised DSM plan filed in the next rate case new demand response programs. The description of new demand response programs should (a) provide sufficient detail on program designs; (b) address the limitations identified in this report (e.g., by accounting for avoided transmission and distribution costs); and (c) demonstrate that the programs will be cost-effective.

We recommend that the Board order NB Power to re-direct the budgeted 2018/2019 funds for demand response programs to the energy efficiency programs, because the energy efficiency programs can deliver cost-effective savings for the Company and its customers.

We recommend that the Board notify the Company that the Board places a high priority on the Smart Habits programs, because of their ability to reduce costs, reduce bills, defer new capital investments, reduce the debt-to-equity ratio, and reduce the costs of GHG constraints. In order to demonstrate that the Board places a high priority on the Smart Habits programs, we recommend that the Board direct the Company to achieve all cost-effective energy efficiency and demand response resources.

Another way for the Board to demonstrate that it places a high priority on the Smart Habits program is to establish guidelines defining how energy efficiency and other distributed energy resources should be planned for, reviewed, and implemented. We recommend that the Board develop guidelines for distributed energy resources, in concert with the guidelines for IRP.

Smart Grid

NB Power's AMI proposal exceeds the $50 million threshold for Board approval of a capital project under subsection 107(1) of the *Electricity Act*. Consequently, the Board is required to review the prudence of this proposal under subsection 107(9) of the *Electricity Act*.

The Company's own economic analysis does not justify the AMI proposal. NB Power estimates that the total cost of the project will be $122.7 million, the total benefits will be $121.4 million, resulting in a net cost to customers of $1.3 million. In addition, NB Power's economic analysis suffers from some important limitations. It understates the cost of the AMI proposal, overstates the benefits associated with the social benchmarking program, understates the potential benefits from conservation voltage reduction opportunities, and does not account for the potential benefits from time-based pricing.

We recommend that the Board reject the Company's AMI proposal, because the Company has not demonstrated that it will be cost-effective. A better benefit-cost analysis, particularly a better estimate of the potential benefits from time-based rates, might indicate that AMI is cost-effective. However, that evidence has not been provided in this docket.

We further recommend that the Board direct the Company to refile a new AMI proposal in next year's rate case. The new AMI proposal should correct for the limitations described in this report, and it should incorporate the time-based rate proposal that the Company is planning to file in the next rate case anyway.

Smart Solutions

In general, the Smart Solutions initiatives appear to be reasonable and consistent with industry practices, regulatory objectives, and the Company's long-term goals. By expanding its existing initiatives (for EVs, smart homes, and demand response) and by introducing new initiatives (for solar, storage, and other products) NB Power estimates it can decrease revenue requirements by $1.1 billion over 25 years. Therefore, we recommend that the Board approve these initiatives.

However, the Company's proposal raises several concerns. First, the program raises concerns about the Company's monopoly status within the electricity sector because NB Power would be offering services potentially provided by competitive, unregulated suppliers. Second, its analysis lacks assessments of the financial and market risks associated with new technologies and nascent markets. As an example, the Company has no New Brunswick-specific research on electric vehicle adoption.

Given these concerns, and given the magnitude and important role of these initiatives, we recommend that the Board monitor the Smart Solutions initiatives closely over time and provide guidance on their implementation. We recommend that the Board direct the Company to provide more details on each of its Smart Solutions initiatives in future rate cases. The Company should provide on-going assessments of the competitiveness of each of the unregulated markets that it participates in. The Company should also provide more detailed business cases for each of the Smart Solutions initiatives, outlining expected costs, benefits, and risks.

Performance Metrics and Reports

Performance metrics and reports can provide useful information for regulators when setting rates, particularly metrics regarding costs, efforts to contain costs, and efforts to improve productivity. NB Power currently uses a variety of key performance indicators (KPIs) and other metrics addressing utility performance across safety, customer, organizational, reliability, and environmental areas.

However, the Company's current metrics and reporting practices are not very useful for informing rate case decisions because they do not include some important performance areas; they are not provided at the outset of a rate case; they are not readily accessible, reviewable, and understandable; and they do not provide lessons learned on what caused under-performance or how to improve future performance.

We recommend that the Board direct the Company to build off of its existing performance metrics and reports to create a Rate Case Performance Report to inform the Board's decision rate cases. These new reports should provide comprehensive information at the outset of each rate case, and address additional performance areas of interest to the Board. The Rate Case Performance Reports should be made publicly available, and should be designed to primarily serve the needs of the Board, but also the needs of the NB Power Board of Directors, legislators, the Public Intervenor, customers, and other industry stakeholders.

1. INTRODUCTION

1.1. Purpose

The New Brunswick Energy and Utilities Board Staff (EUB Staff) commissioned Synapse Energy Economics (Synapse) to review the 2018/2019 General Rate Case application recently filed by the New Brunswick Power Corporation (NB Power or the Company). Our task was to review, critique, and make recommendations on the issues of revenue requirements, the rate adjustment mechanism (RAM), the 2017 integrated resource plan (IRP), and the Energy Smart program—with an emphasis on the demand-side resources and advanced metering infrastructure (AMI) elements within that program.

1.2. Qualifications

The authors' qualifications are summarized below. Additional information regarding Synapse Energy Economics and the authors is available at: www.synapse-energy.com.

Synapse Energy Economics

Synapse Energy Economics, Inc. is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has become a leader in providing rigorous technical analysis of the electric power sector for public interest and governmental clients.

Synapse's staff of 30 includes experts in energy and environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, transmission and distribution (T&D), rate design and cost allocation, risk management, cost-benefit analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets. Several of our senior-level staff members have more than 30 years of experience in the economics, regulation, and deregulation of the electricity and natural gas sectors, and have held positions as regulators, economists, and utility commission and ISO staff.

Services provided by Synapse include economic and technical analyses, regulatory support, research and report writing, policy analysis and development, representation in stakeholder committees, facilitation, trainings, development of analytical tools, and expert witness services. Synapse is committed to the idea that robust, transparent analyses can help to inform better policy and planning decisions. Many of our clients seek out our experience and expertise to help them participate effectively in planning, regulatory, and litigated cases, and other forums for public involvement and decision-making.

Synapse's clients include public utility commissions in U.S. states and Canada, offices of consumer advocates, attorneys general, environmental organizations, foundations, governmental associations, public interest groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Our work for other international clients has included projects for the United Nations Framework Convention on Climate Change, the Global Environment Facility, and the International Joint Commission, among others.

Tim Woolf

Tim Woolf is the Vice President at Synapse Energy Economics. He has more than 30 years of experience analyzing technical and economic aspects of energy and environmental issues. Before returning to Synapse in 2011, he served four years as a commissioner at the Massachusetts Department of Public Utilities (DPU), where he played a leading role in developing the Commonwealth's aggressive clean energy policies.

Mr. Woolf's primary areas of focus include electricity industry regulation and planning, power sector transformation, energy efficiency program design and policy analysis, technical and economic analyses of electricity systems, renewable resource technologies and policies, clean air regulations and policies, and many aspects of consumer and environmental protection.

In recent years he has focused on all topics related to power sector transformation, including: cost-benefit analyses of distributed energy resources, assessment of non-wires alternatives, distribution system planning, performance-based regulation, and new utility business models. He also addresses a variety of related ratemaking issues such as rate design, dynamic pricing, net metering rates, and decoupling.

Mr. Woolf has testified as an expert witness in more than 45 state or provincial regulatory proceedings, and has authored more than 60 reports on electricity industry regulation and restructuring. He represents clients in collaboratives, task forces, and settlement negotiations, and he has published articles on electric utility regulation in *Energy Policy*, *Public Utilities Fortnightly*, *The Electricity Journal*, *Local Environment, Utilities Policy*, *Energy and Environment*, and *The Review of European Community and Environmental Law*.

Mr. Woolf holds an MBA from Boston University, a Diploma in Economics from the London School of Economics, and a BS in Mechanical Engineering and a BA in English from Tufts University.

Asa Hopkins

Asa Hopkins, PhD, is a Principal Associate at Synapse Energy Economics. He is an expert in the development and analysis of public policy and regulation regarding energy and GHG emissions. His work includes cost-benefit analysis, stakeholder engagement, state energy planning, and utility planning. He has provided analysis and testimony in both legislative and regulatory contexts, including state utility regulation and state and federal rulemaking.

Since arriving at Synapse in early 2017, Dr. Hopkins has focused on utility and demand-side issues, including demand response in Quebec, rate design in Massachusetts, and utility performance metrics in Puerto Rico. He has also performed multi-state analysis of strategic end-use electrification across the Northeast region.

As the Director of Energy Policy and Planning at the Vermont Department of Public Service from 2011–2016, Dr. Hopkins was responsible for the development and analysis of state policy regarding renewable energy, ratepayer-funded energy efficiency, energy-related economic development, and innovative utility rates and programs. He was responsible for developing the state's Comprehensive Energy Plan, reviewing utility integrated resource plans, and directing the actions of the Planning and Energy Resources Division. He also served on the Board of Directors of the National Association of State Energy Officials. During his tenure, Vermont rose in the rankings on national clean energy state scorecards.

Prior to 2011, Dr. Hopkins was an AAAS Science and Technology Policy Fellow in the Office of the Under Secretary for Science at the U.S. Department of Energy. In that role, he managed stakeholder engagement for and the overall project flow of DOE's first Quadrennial Technology Review. Dr. Hopkins came to DOE from Lawrence Berkeley National Laboratory, where he worked on economic and market analysis of appliance energy efficiency standards.

Dr. Hopkins holds a BS in Physics from Haverford College and a Masters and PhD in Physics from California Institute of Technology.

Melissa Whited

Principal Associate Melissa Whited specializes in issues related to utility regulation and rate design. She focuses in particular on the fundamental changes in the electricity industry spurred by declining energy use and rapidly increasing penetration of distributed energy resources. Ms. Whited consults on the tools to effectively address these changes, including performance-based regulation, revenue decoupling mechanisms, distribution system planning, and innovative rate design. Ms. Whited has testified before the Massachusetts Department of Public Utilities, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission.

Ms. Whited led the development of a handbook for regulators on utility performance incentive mechanisms, which describes best practices in mechanism design and how such mechanisms can help utilities transition to alternative business models. In addition, Ms. Whited has provided consulting services regarding the incorporation of distributed energy resources in utility planning processes in New York's "Reforming the Energy Vision" proceeding.

In the rate design arena, Ms. Whited's work focuses on the development of rate designs that effectively balance the fundamental principles of revenue sufficiency, fair apportionment of costs, and efficiency of use. She has authored numerous reports and testimony regarding the impacts of fixed charges and demand charges on low-income customers, customers with distributed generation, and the ability of states to achieve their energy policy goals.

Ms. Whited holds two master's degrees from the University of Wisconsin: an MA in agricultural and applied economics and an MS in environment and resources.

Kenji Takahashi

Kenji Takahashi is a Senior Associate at Synapse. He conducts economic, environmental, and policy analysis of electric system technologies, policies, and regulations associated with both supply- and demand-side resources. He has extensive experience in the analysis of integrated resource plans, load forecast, renewable energy policies, distributed generation, demand response, and electric and gas energy efficiency measures and programs.

He has assessed the design and impact of utility energy efficiency program plans in utility program filings and integrated resource planning proceedings for numerous utilities in the United States and several Canadian provinces. He has also assessed rate and bill impacts, job impacts, and emissions impacts of clean energy programs and scenarios.

Mr. Takahashi has analyzed the performance, costs, benefits, potential, and policies of renewable energy and energy efficiency measures and resources. These have included state-of-art measures such as cold climate heat pumps, deep energy retrofits, net zero energy buildings, and strategic energy management. Recently, he helped analyze heat pumps and strategic electrification for the Northeast Energy Efficiency Partnerships. He also presented direct testimony to the Massachusetts Department of Public Utilities regarding Berkshire Gas's Long-Range Forecast and Supply Plan, in which he analyzed and critiqued the Company's natural gas load forecast and demand-side resource assessment.

Alice Napoleon

Alice Napoleon is a Senior Associate at Synapse. She is an electric system policy analyst focusing on review of energy efficiency program design, administration, cost recovery, and cost-benefit analysis. In her 12 years at Synapse, she has co-authored dozens of energy analysis reports. She has completed major projects for the U.S. Environmental Protection Agency on quantifying the benefits of clean energy resources and for the U.S. Department of Energy on strategic energy management. In collaboration with the Industrial Energy Analysis group of Lawrence Berkeley National Laboratory, she is currently managing the development of a toolkit for energy efficiency program administrators to incorporate the U.S. Department of Energy's Superior Energy Performance™ and strategic energy management programs into their portfolios.

Ms. Napoleon has provided testimony and testimony assistance before public utility commissions across the United States and Canada, including in California, Delaware, Illinois, Kentucky, Missouri, New Jersey, Nova Scotia, South Carolina, and Virginia. She provided extensive and ongoing expert analysis and support for the State of New Jersey regarding its state- and utility-administered residential, low-income, commercial, and industrial energy efficiency and combined heat and power programs. Ms. Napoleon conducted extensive research on current low-income electric energy efficiency program efforts in U.S. states and submitted testimony regarding administration of low-income energy efficiency services and implementation of advanced metering in Nova Scotia.

In addition to strong analytical skills, Ms. Napoleon has expertise and extensive experience facilitating collaborative stakeholder processes, including facilitating and providing technical analysis in support of demand-side resource policy working groups in Colorado, Maryland, and South Carolina. Currently, she serves as a member of the National Energy Efficiency Registry Advisory Committee. She holds an MA in Public Administration from the University of Massachusetts at Amherst and a BA in Economics from Rutgers University.

2. REVENUE REQUIREMENTS

2.1. New Brunswick Power's Proposal

NB Power is proposing to increase electricity rates for the 2018/19 fiscal year by 2.0 percent on average across all rate classes. This percentage rate increase was determined by the Company by balancing the two statutory goals of (a) achieving a 20 percent equity target as soon as is reasonable, and (b) keeping rates as low as possible and making any changes in rates stable and predictable from year to year (NB 4.02, Revised Evidence, page 5).

The request for an even 2.0 percent increase in rates is consistent with the Company's requested rate increase in the previous rate case, and it is consistent with the proposed rate increases for the next five fiscal years in the Company's 10-Year Plan (NBP 1.11, NB Power's 10-Year Plan, Figure 1). In all three instances, NB Power has set the rate increase as high as possible in order to achieve its 20 percent equity target within a reasonable time period, but has chosen not to exceed a 2.0 percent average rate increase in order to keep rates low.

In sum, the proposed rate increase is driven by three key factors: (a) the need to recover anticipated revenue requirements; (b) the need to reduce debt; and (c) an effective cap on rates at an amount that is perceived by the Company to be low, stable, and predictable. The net earnings achieved each year is the amount that NB Power uses to reduce its debt. Thus, after the Company has set its other revenue requirements, it increases the net earnings as much as possible within the effective 2.0 percent rate cap.

Table 1 summarizes the revenue requirements that the Company seeks to recover in 2018/19, along with a comparison to the revenue requirements that the Board allowed the Company to recover in the 2017/18 general rate case (NBP 11.02, Revised Evidence, Table 3.0.1, page 19). The increases in operations, maintenance, and administration (OM&A) and depreciation and amortization are responsible for almost all of the increases in revenue requirements.

Table 1. NB Power's revenue requirement proposal (in millions $)

	2018/19 Proposed	2017/18 Allowed	Variance	Percent of Total Proposed
Fuel and purchased power	597.1	634.8	(37.7)	35%
OM&A	499.1	468.4	30.7	29%
Depreciation and amortization	274.1	250.6	23.8	16%
Taxes	45.1	44.3	0.8	2%
Finance costs and other income	216.0	220.9	(4.9)	13%
Net change in regulatory balance	11.3	11.4	(0.0)	1%
Net earnings	62.3	90.6	(28.2)	4%
Total revenue requirement	1,705.5	1,720.9	(15.5)	100%

The total revenue requirement in 2018/19 is estimated to be less than that for the previous rate case by $15.5 million. This is partly due to a considerable reduction in fuel and purchased power costs. It is also driven in part by reduced net earnings of $28.2 million. As described above, however, this reduction in net earnings is applied in order to achieve the effective rate increase cap of 2.0 percent. The actual impact of reducing the net earnings for 2018/19 is to defer the point in time when the 20 percent debt target is achieved, assuming all else being equal.[1]

Table 1 also presents the portion of the total revenue requirement that is made up by each category. As indicated, fuel and purchased power and OM&A are by far the largest contributors to revenue requirements.

2.2. Industry and Regulatory Context

There are several important factors regarding the New Brunswick electricity industry that the Board should consider when reviewing revenue requirement proposals.

Industry Context

First, NB Power's in-province energy sales are expected to remain flat well into the future. The Company forecasts that the average annual growth rate from 2017/18 through 2026/27 will be only 0.1 percent (NBP 1.36, Appendix S, 2018–2027 Load Forecast Update, Table 1, page 3). In general, relatively low sales growth will make it more difficult for NB Power to recover increasing costs without raising rates. On the other hand, peak demand growth is expected to be slightly negative, with an average annual growth rate of −0.7 percent. In general, low peak demand growth can help defer the need for new capital investments in generation facilities.

Second, NB Power's out-of-province sales have declined significantly in recent years. Table 2 presents the actual and estimated out-of-province sales for 2015/16 through 2018/19 (NBP 11.02, Revised Evidence, Table 4.2.1, page 133). Over these four fiscal years, the total amount of out-of-province sales reductions has been equal to2,635 GWh, which is roughly 57 percent of the sales in 2015/16. These reduced off-system sales result in reduced margins, which means that NB Power must look to other sources for meeting its revenue requirements.

Table 2. NB Power's out-of-province sales in recent years

	Total Sales (GWh)	Sales Reduced GWh)	Sales Reduced
2015/16 actual	4,597	---	---
2016/17 actual	3,360	-1,237	-27%
2017/18 estimated	2,988	-372	-11%
2018/19 budgeted	1,962	-1,026	-34%

1 At the time of the previous 10-Year Plan, the Company expected to reach the 20 percent debt target by 2024, whereas the most recent 10-Year Plan indicates that the Company can reach the target by 2025 (NB Power's 10-Year Plans 2018–2027 and 2019–2028, Figure 1).

Third, several key cost components are increasing over time. Table 3 presents recent trends in the revenue requirements associated with OM&A and depreciation and amortization (NBP 11.02, Revised Evidence, Table 3.0.1, page 19). In general, these costs have increased at a rate well above the 2.0 percent rate increases that the Company hopes to apply for over the next several years. If these trends continue, it will become increasingly challenging for the Company to meet both goals of reducing debt and maintaining low rates.

Table 3. NB Power's OM&A and depreciation & amortization in recent years

	OM&A (mil$)	OMA (growth)	Depreciation (mil$)	Depreciation (growth)
2015/16 actual	450.2	---	225.9	---
2016/17 actual	482.8	7%	233.2	3%
2017/18 estimated	496.5	3%	252.1	8%
2018/19 budgeted	499.1	1%	274.4	9%

Fourth, NB Power has a history of exceeding its budgeted or approved costs. This trend was identified in the previous rate case by Mr. Knecht in his evidence on behalf of the New Brunswick Public Intervenor (Robert Knecht, In the Matter of NB Power's 2017/18 General Rate Application, Matter 336 PI 1.01 pages 15–16). This trend continues in the 2017/18 fiscal year, where the Company's revenue requirements are expected to be roughly $15 million higher than was approved by the Board. This was mostly driven by the increase in OM&A revenue requirements (NBP 11.02, Revised Evidence, Table 3.0.1, page 19). The trend is notable because it suggests that the Company might be having trouble forecasting and/or controlling costs, and that the Board's approval of budgets might have little bearing on that issue.

Fifth, NB Power will be required to pay some form of carbon charges in the near future. On December 12, 2015, Canada inscribed in the Paris Accord its 2030 target of 30 percent reduction in GHG emissions from 2005 levels. Specific requirements for meeting this target have yet to be established, and NB Power is working with the Government of New Brunswick and the federal government to develop a made-in-New Brunswick GHG management strategy. NB Power might be required to shut down the Belledune coal plant early (by 2030), and it might be subject to carbon charges consistent with the Pan-Canadian Framework on Clean Growth and Climate Change (Canada, 2016). In its 2017 IRP, the Company conducted a sensitivity analysis assuming it was subject to a carbon charge of $10 per tonne in 2018, rising to $50 per tonne in 2022 (NBP 5.01, NB Power, 2017 IRP, Part A, page 36). These types of GHG requirements will undoubtedly have many implications for future resource planning and the resulting revenue requirements.

Sixth, the Company does not need to invest in new generation capacity for many years. The forecast of low peak demand growth and the savings from the Energy Smart program mean that the Company does not need to construct a major new generation project until 2031 or beyond. This gives NB Power a window of time to build up its equity before needing to make a large capital investment.[2] It also gives NB Power time to investigate and plan for opportunities to optimize its mix of resources before the next major generation station is required. These opportunities include the implementation of distributed energy resources and other low-GHG resources.[3]

Seventh, there are increasing opportunities in New Brunswick and the region for implementation of growing levels of distributed energy resources. NB Power recognizes and hopes to take advantage of these new opportunities through its Energy Smart program.[4] These resources can play a pivotal role in reducing future revenue requirements by helping to reduce fuel costs, defer or avoid capital costs, and reduce GHG emissions.

These factors create several challenges for NB Power, both in the near term and the long term. Low sales growth in-province and out-of-province, combined with rising costs and increasing pressure to reduce GHG emissions, will make it increasingly difficult for the Company to balance its goals of reducing debt and maintaining low rates.

On the other hand, the lack of need for investments in new generation capacity for as many as 10 years into the future, and the relatively low capital investment forecast between now and the major capital investments in the Mactaquac project, provide the Company with more time to plan. It can use this window of opportunity to identify ways to increase operating efficiency, reduce costs, and develop cost-effective and clean distributed energy resources.

Regulatory Context

As noted above, NB Power's rate request is driven by (a) its revenue requirements, (b) the goal of increasing equity, and (c) the goal of keeping rates low. Consequently, reducing revenue requirements should be a top priority for the Company and the Board, as this will help to both increase equity and keep rates low.

NB Power is not subject to the same type of regulatory pressures as investor-owned utilities in other jurisdictions. First, the Board has limited ability to disallow cost over-runs or imprudently incurred costs, because NB Power is a publicly owned utility and does not have private equity shareholders to absorb those costs. In its decision in the previous rate case, the Board ordered a reduction in the Company's 2017/18 revenue requirements of $4.7 million, resulting in total revenue requirements of $1,720.9 million (Board Partial Decision, Matter 336, March 2017). However, NB Power is expecting to overspend its 2017/18 total allowed revenue requirement by $14.9 million (NBP 11.02, Revised Evidence, Table

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2 NB Power will need to make some large investments in the near- to mid-term future on some capital projects, such as the Mactaquac Capital project (NB 11.02, Revised Evidence, November 2017, page 3; and NB 1.11, Appendix C, NB Power 10-Year Plan, Figure 8, page 18). But these are generally smaller than what is required for a new generation facility.

3 We use the term distributed energy resources to refer to energy efficiency, demand response, distributed generation, distributed batteries, and EVs.

4 As described in in Chapter 4, NB Power does not take full advantage of the potential for distributed energy resources in its 2017 IRP.

3.0.1, page 19). The only financial effect on NB Power of this overspending is to defer the date at which the 80 percent debt target is reached.

Second, some of the regulatory mechanisms increasingly in use in other jurisdictions to improve utility productivity and performance are much less effective when applied to publicly owned utilities. For example, multi-year rate plans (MRPs), which provide financial incentive to increase productivity and reduce costs between rate cases, do not provide effective financial impact in the absence of private equity shareholders.[5] Performance incentive mechanisms, which provide direct financial rewards for achieving specific performance targets, also have much less impact on a utility without private shareholders.[6]

Third, the *Electricity Act* allows NB Power to have a rate case every year and to propose budgets for all of its revenue requirements for each upcoming year. This allows the utility to recover most, if not all, of its costs in a very timely way, compared with other utilities that use historical test years and have to wait several years between rate cases to increase rates. This delay between costs incurred and costs recovered is referred to as regulatory lag, and it is presumed to provide utilities with pressure to reduce costs (US DOE, 2017, page 3-2).

Fourth, NB Power is requesting to introduce a RAM to help reduce the volatility of revenues collected and help expedite achievement of its debt/equity goal. We address this issue in detail in Chapter 3. If the Board were to approve this request, it would further reduce the pressure on the Company to reduce costs, by facilitating and streamlining the recovery of costs that are not fully accounted for in rate case budgets.

This regulatory context means that NB Power is subject to relatively little financial pressure to reduce costs. In addition, the Board has relatively few options for encouraging the Company to reduce costs. This is particularly troublesome given the industry context described above, where maintaining low costs will be necessary for meeting the goals of reducing debt and keeping rates low.

2.3. Conclusions and Recommendations

Balancing Statutory Goals

NB Power claims that a 2.0 percent increase in rates complies with the statutory requirement to keep rates as low as possible and ensure that changes in rates are stable and predictable from year to year. We agree that a maximum 2.0 percent rate increase in this rate case would be consistent with the statutory goal of keeping rates low and stable, particularly in light of the other statutory goal of reducing debt.

5 For a useful reference on performance-based regulation, see LBNL 2016. For a useful reference on MRP experience, see US DOE 2017.

6 For a useful reference on PIMs, see Synapse 2015.

However, NB Power should not plan on increasing rates by 2.0 percent per year indefinitely. In its most recent 10-Year Plan NB Power projects continued rate increases of 2.0 percent per year through 2023 (NBP 1.11, NB Power's 10-Year Plan 2019-2028, Figure 1). In its previous 10-Year Plan NB Power projected continued rate increases of 2.0 percent per year through 2021; two years earlier than the current Plan (NB Power's 10-Year Plan 2018-2017, Figure 1). There is a risk that the date by which the Company will increase rates by less than 2.0 percent will continue to be pushed forward into the future.

We agree with NB Power's strategy of achieving a debt/equity ratio of 80 percent as soon as is practically reasonable. In addition to the statutory requirement, reducing the Company's debt should reduce financial risks and increase financial flexibility, particularly in the mid- to long-term future as the Company's capital investments increase.

However, this debt goal must be balanced with the goal of maintaining low rates. With each rate case, the Company and the Board are faced with the challenge of seeking the appropriate balance between these two competing goals. We recommend that the Board direct the Company to give a preference to the goal of maintaining low rates, if such a preference is necessary to maintain the effective rate cap described above. Such a preference is appropriate given that the Act does not specify when the Company must meet the 80 percent debt/equity ratio, and the Company has several years before it needs to make large capital investments requiring substantial new debt. It is also appropriate because it sends an important message to the Company regarding the need to maintain low rates. This last point is addressed in the remainder of this chapter.

The Importance of Reducing Costs

As described above, NB Power faces a pressing need to reduce its costs, or at least reverse the trend of rising costs. Maintaining low costs will be necessary for achieving the two goals of increased equity and low rates, in light of limited load growth and forthcoming GHG requirements.

While there are many costs that the Company has little control over, there are also many costs that it can control or influence. One way for NB Power to reduce costs is through increased productivity, particularly for OM&A costs. Another way to reduce costs is to defer or avoid new capital costs and new capital-intensive generation investments.

As important as this goal of reducing costs is, the Board has relatively few options for encouraging the Company to achieve it. Cost disallowances, MRPs, and PIMs are ineffective for a utility that does not have private equity shareholders. Nonetheless, the Board should use every regulatory tool at its disposal to encourage, induce, or incentivize the Company to reduce costs.

Regulatory Guidance and Pressure

In this context, the primary options for the Board to encourage reduced costs can be described as regulatory guidance and regulatory pressure. The Board can provide regulatory guidance by approving (or disapproving) specific projects or investments, especially innovative projects such as Smart Habits or AMI. The Board can provide guidance by signaling to the Company how to prioritize investments, how to optimize resources, how to balance short-term versus long-term interests, and how to balance the goals of reducing debt and maintaining low rates.

The Board can provide regulatory pressure through detailed review and oversight of NB Power's proposed budgets and revenue requirement requests. We recommend several ways for the Board to expand its oversight of NB Power's rate case filing.

First, we recommend that the Board direct the Company to file a Rate Case Performance Report in each rate case, to help inform the Board's rate case decisions. These new reports should build off the Company's current metrics and reporting practices to help the Board understand how well the Company is performing, and how successful it is in controlling costs. (See Chapter 9 for more detail on performance metrics and related recommendations.) Performance metrics can be used to compare NB Power with its own historical performance, as well as with the performance of other, similar utilities. Performance metrics can be used to inform the Company, the Board, the NB Power Board of Directors, the Legislature, and other stakeholders whether NB Power is operating efficiently and where it might be able to improve its productivity. This information can be used to inform Board decisions about future revenue requirements and the goals of reducing debt and maintaining low rates.

Second, we recommend that each rate case review focus on those types of costs that the utility might have the most ability to control. We have not had the opportunity to conduct an in-depth assessment of what those costs might be or how they might be controlled. Nonetheless, we identify several examples of the types of costs that should be considered for focused metrics, reporting, and regulatory review. These include:

- Fuel and purchased power expenses: These represent 35 percent of the total revenue requirements requested for 2018/19. Some of the fuel expenses are driven by fuel prices over which the Company has little control. Many of the purchased power costs are due to long-term purchased power agreements, many of which are required by law, and many of which will remain in place for several more years. Nonetheless, there might be several opportunities for NB Power to reduce fuel and purchased power expenses over the medium- to long-term future. For example, improved IRP practices and expanded distributed energy resource implementation could help to optimize the Company's mix of resources, reduce fuel costs, and reduce the need for or cost of future purchased power agreements.[7] As another example, the joint dispatch initiative with Nova Scotia could be built upon to create a single balancing authority for the Maritime provinces, leading to improved power plant operations and reduced fuel costs.
- OM&A costs: These represent 29 percent of total revenue requirements requested for 2018/19. They have increased consistently in recent years, and the actual OM&A costs frequently exceed the budgeted costs or those approved by the Board. Within this category of costs, Point Lepreau Nuclear Generating Station (PLNGS) costs represent the largest share (36 percent), followed by distribution (17 percent), corporate services (17

[7] For example, the Grandview (95 MW) and Bayside (225 MW) natural gas purchased power agreements are due to expire in 2025 and 2027, respectively (NBP 5.01, 2017 IRP Part A, Figure 13, page 24).

percent), and generation (14 percent). Among the different OM&A expenses, labor costs are by far the largest portion (64 percent), followed by hired services (25 percent).

- Senior management salaries: These fall within the labor costs and thus represent an important component of OM&A costs. The Board may want to monitor these salaries to link them to the performance of the Company. The Board may also want to allow higher senior management salaries based upon good company performance, and *vice versa*, as indicated by the new reporting requirements described above. The Board should apply particular attention to the Company's cost-containment initiatives and budget over-run results.
- Non-essential costs: In each rate case, the Board should review those costs that are not essential for reliability or for providing low-cost electricity services over the long term. For example, this might include costs for research, development, and demonstration activities. This might also include some elements of grid modernization initiatives or AMI projects. While some of these initiatives might provide value and be in the public interest over the long term, it may be more appropriate to defer or eliminate some of them in order to meet the Company's debt equity goal. Once that goal is met, then the Company can give greater priority to some of these non-essential initiatives. In general, the Board should be skeptical of projects that are non-essential and are not clearly cost-effective.

Third, we recommend that the Board expand its oversight of the Energy Smart program, especially the Smart Habits program. Cost-effective distributed energy resources implemented through the Energy Smart program can help to significantly reduce costs over the long term. Experience in other jurisdictions indicates that considerable regulatory guidance and support is necessary to ensure the successful implementation of all cost-effective distributed energy resources. We recommend that the Board establish guidelines to assist the development of future IRPs, because IRPs play an important role in reducing costs through resource optimization and identifying the full potential for distributed energy resources. (For more detail on IRP and related recommendations see Chapter 4.) These guidelines should also address the design and implementation of energy efficiency and demand response programs. Such programs can help defer or avoid future capital expenses, and they provide a low-cost option for reducing GHG emissions. (For more detail on Smart Habits and related recommendations see Chapter 6.)

3. RATE ADJUSTMENT MECHANISM

3.1. New Brunswick Power's Proposal

NB Power is proposing a new RAM to allow it to recover costs associated with extraordinary events, including costs that are unanticipated, incremental to its budgets, and outside of its control. The Company's primary rationale for this mechanism is that it would allow the Company to fully recover all prudently incurred costs (NBP 11.02, Revised Evidence, page 13). The Company also notes that a RAM would improve earnings results and make it easier to meet financial projections (NBP (NBEUB) IR-90).

NB Power proposes that it be allowed to submit claims for recovery of costs associated with extraordinary events in each rate case, for any such costs incurred in the previous fiscal year (NBP 11.02, Revised Evidence, page 16). NB Power would be required to demonstrate the eligibility of such costs using four criteria: (a) NB Power would have to notify the Board within six months of the extraordinary event; (b) costs would be recovered from deferral accounts; (c) NB Power would not have been able to plan for and budget for the extraordinary costs; and (d) the extraordinary costs would have to be incremental to those already being recovered in rates (NBP 11.02, Revised Evidence, page 17).

The Company has not fully defined which costs it would expect to recover through the RAM. It cites storm damage costs as one example (NBP 11.02, Revised Evidence, pages 14-15). The Company notes that "it is not possible to create definitive and exhaustive lists of all possible events and identify them as controllable or uncontrollable," but it is currently trying to address costs that are most clearly beyond its control (NBP (NBEUB) IR-90). NB Power also notes that it is not currently attempting to recover fuel and purchased power expenses through the RAM, because it requires additional time to sort through the issues and obtain input from stakeholders (NBP 11.02, Revised Evidence, page 15).

NB Power filed a report in this rate case summarizing the experience with RAM-like recovery mechanisms in other Canadian provinces (NBP 8.96, NBP (NBEUB) IR-98(a), Elenchus RAM Report). This report also provides findings and recommendations for eligibility criteria; for recovery of O&M costs, capital, and transmission costs; for the time period for recovery of costs; and for definitions related to the RAM.

3.2. Regulatory Context

NB Power does not currently include costs for unanticipated events, such as storm costs, in its revenue requirement budgets. Consequently, when it does incur unanticipated costs, the primary effect is to lower retained earnings for that year. As described in Section 3.3, smaller retained earnings reduce the Company's ability to reduce debt and delay the point in time when the Company achieves its 80 percent debt target.

The Elenchus RAM report provides several examples of other Canadian provinces that have cost recovery mechanisms similar to the Company's RAM proposal. In many cases, this includes a Z-factor as one component of a PBR mechanism (e.g., British Columbia, Alberta, Manitoba, Ontario, and Quebec). In some cases, this includes an energy cost adjustment mechanism to pass through to customers the fluctuations in energy costs (e.g., Prince Edward Island). In other cases, it includes a contingency for storm costs built into the cost budgeting process (e.g., Nova Scotia) (NBP 8.96, NBP (NBEUB)IR-98(a), Elenchus RAM Report).

The Elenchus RAM report finds that the only examples of rate riders with deferral accounts occur in jurisdictions that have some form of PBR in place (NBP 8.96, NBP (NBEUB)IR-98(a), Elenchus RAM Report, page 1). This is a critical distinction because it highlights the importance of ensuring that any rate rider or RAM should be designed to fit with the other ratemaking provisions and the overall regulatory context. For example, Z-factors are often included in a PBR mechanism because they require the utility to not file a rate case for a pre-determined period, such as five years. The rate case stay-out period is designed to provide the utility with an incentive to reduce costs between rate cases. In this context, a Z-factor might be necessary to ensure that large unanticipated costs do not cause financial harm to the utility or otherwise undermine the PBR mechanism.

NB Power, in contrast, is not subject to a PBR mechanism. It is required to file a rate case each year, which is essentially the opposite of a rate case stay-out provision. Therefore, the primary rationale for many of the RAM-like mechanisms in other provinces does not apply to New Brunswick.

Further, NB Power has different regulatory priorities than other jurisdictions. NB Power priorities include reducing debt, maintaining low rates, and reducing costs. The Company’s RAM proposal should be evaluated from this perspective, not the perspective of other utilities subject to PBR.

The absence of a PBR mechanism creates another important difference. PBR mechanisms, particularly the rate case stay-out provision, are designed to encourage utilities to increase their productivity and reduce costs. Regulatory lag is the main driver for this incentive. NB Power, in contrast, does not have this sort of regulatory incentive to increase productivity and reduce costs. This means that the Board must use alternative approaches to encourage the Company to reduce costs. (See Chapter 4 for more detail.) The RAM proposal runs the risk of reducing the pressure on the Company to reduce costs, and therefore is less appropriate than it would be for a utility that is subject to PBR.

3.3. Advantages of the Rate Adjustment Mechanism

In the New Brunswick regulatory context, the primary advantage of establishing a RAM is that it should help the Company meet its debt reduction goals. Unrecovered costs in any single year result in a reduction in net earnings, an increase in debt, and a deferral of the date by which the Company meets its 80 percent debt target. In New Brunswick, where debt reduction is a high priority, this is a fairly compelling rationale for some form of RAM.

The proposed RAM will also help stabilize the NB Power’s revenues and allow the Company to recover more of its actual incurred costs. However, this is not a very compelling argument supporting the RAM, because NB Power is already able to recover a large portion of its actual costs as a result of its annual rate cases.

3.4. Disadvantages of the Rate Adjustment Mechanism

There are several disadvantages of the proposed RAM. First, it reduces the incentive for NB Power to mitigate costs. With increased likelihood that NB Power will be able to recover all costs associated with extraordinary events, there is less pressure on the Company to control those costs. It is important to note that even those costs that are somewhat beyond the control of the Company may not be entirely beyond its ability to influence. For example, consider storm recovery costs, which are frequently cited as beyond the utility's control. While it is true that the storm itself is beyond the utility's control, there may be ways that a utility could reduce its costs of responding to the storm. Costs could be reduced through better vegetation management practices, better emergency planning practices, better communications systems and practices, better staff training on emergency response, and improved coordination of workforces with neighboring utilities. The Company's incentive for taking such steps is reduced with the proposed RAM.

Second, the proposed RAM will result in rate increases that are higher than what would occur in the absence of a RAM. These higher rate increases could conflict with the Electricity Act's requirement to maintain low rates. If the Board decides that a 2.0 percent annual rate increase is a reasonable cap on rates, the proposed RAM would make it more difficult to maintain that cap because it could result in rate increases that exceed 2.0 percent.

Third, the RAM might result in less regulatory oversight and less transparency of NB Power initiatives and expenditures. Unless the eligibility criteria for the RAM is clear, narrowly defined, and carefully applied, the Company could pass costs through the RAM that are not necessarily extraordinary or beyond its control.

Fourth, it may be challenging for the Board to clearly define expenditures that are outside of NB Power's control. As indicated in the example above, even storm recovery costs might include some elements over which the Company has control. NB Power's unwillingness to fully define the costs that might be subject to the RAM should be a warning to the Board that the definition of RAM eligibility could be a challenging and contentious issue.

Fifth, the proposed RAM will result in less stable rates for customers. Reduced stability for customers is the flip side of increased stability for the Company. This outcome could conflict with the Electricity Act's requirement to provide electricity rates that are stable and predictable from year to year.

3.5. Conclusions and Recommendations

We conclude that the disadvantages of the proposed RAM outweigh the advantages. The proposed RAM could result in less incentive to reduce costs and less regulatory oversight. More automatic cost recovery could dilute the Company's interest in reducing the magnitude of extraordinary expenditures. In sum, the proposed RAM could result in reduced accountability from NB Power.

The proposed RAM raises the need for the Company and the Board to balance the two competing goals of reducing debt and maintaining low rates. As described in Section 2.3, we recommend that the Board direct the Company to give a slight preference to the goal of maintaining low rates. This preference supports our conclusion that the disadvantages of the proposed RAM (increased rates) outweigh the advantages (reduced debt).

Therefore, we recommend that the Board reject the Company's proposed RAM at this time.

If the need to reduce debt increases over time, then the Board could consider some form of RAM, primarily for that purpose. Further, if the Board decides to establish a RAM, it should only do so if certain conditions are met, including:

- NB Power demonstrates that the proposed RAM complies with the interim international accounting reporting standard (IFRS).
- The Board establishes performance metrics and other measures to encourage NB Power to reduce costs. (See Section 2.3 and Chapter 9 for further discussion.)
- The Company agrees to make any potential RAM rate increases fully transparent, both in rate cases and 10-Year Plan forecasts.
- The Company agrees to consider the RAM rate increases when achieving the statutory goal of maintaining low rates. In particular, if the Company seeks to keep rates within an effective 2.0 percent rate cap, that rate cap calculation must include the potential rate increase from the RAM.
- The Board establishes criteria for how to define extraordinary expenses that might qualify for the RAM. This would include criteria for determining whether such expenditures are outside NB Power's control.

4. INTEGRATED RESOURCE PLANNING

4.1. New Brunswick Power's IRP

NB Power submitted to the Board its IRP on December 2, 2017 as part of its 2018/19 General Rate Application. The IRP assesses New Brunswick's future electricity demand requirements and least-cost energy plans to meet the electricity demand over a 25-year horizon.

This assessment encompasses both supply and demand options. On the supply side, the plan includes retirement of existing, aging power plants as fixed assumptions and evaluates building new power plants. On the demand side, the plan includes energy impacts from a cost-effective Energy Smart New Brunswick (NB) program consisting of energy efficiency, demand response, and smart grid.

NB Power used a system expansion model called PROVIEW to assess "the least-cost supply plan to reliably meet the forecast future requirement of load and reserve within New Brunswick, with consideration of the renewable portfolio standard (RPS) requirement of 40 per cent by 2020" (NBP 5.01, 2017 IRP Part A, p. 60).

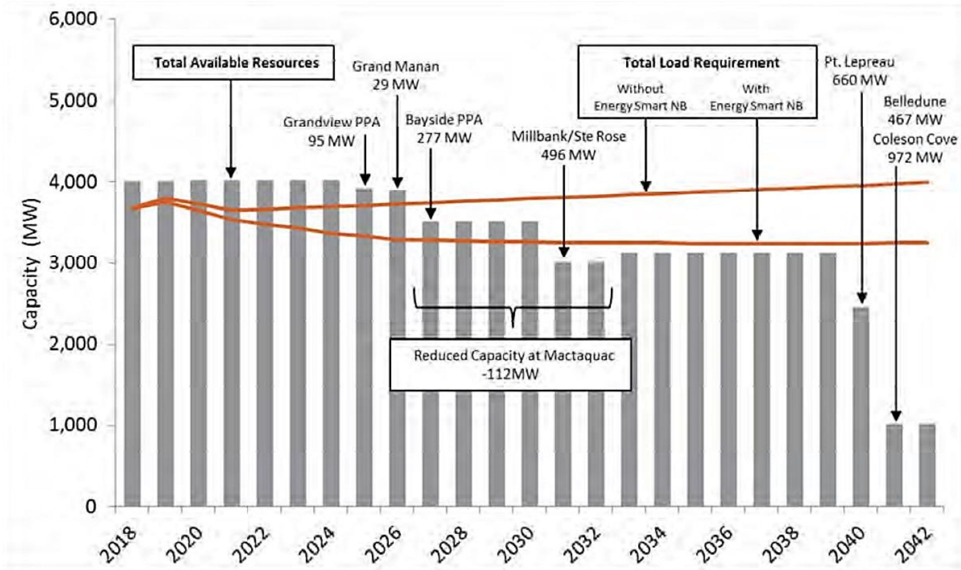
According to NB Power, the IRP uses the assumptions based on the best information available at the time of writing (NBP 5.01, NB Power 2017 IRP Part A, p. 3). The IRP also includes sensitivity analysis with an objective of identifying the least-cost integrated plan that remains robust with changes in critical assumptions (NBP 5.01, 2017 IRP Part A, p. 9).

One of the main objectives of the IRP is to develop a plan "that responds to the *Electricity Act* and operates under the policy objectives to provide low and stable rates, to ensure a reliable power system and to meet the requirements of the RPS" (NBP 5.01, 2017 IRP Part A, p. 9). Further NB Power states that the IRP provides a plan for NB Power to move towards sustainable electricity while incorporating what its customers care about most: affordability, clean energy, and new personal options and services (NBP 5.01, 2017 IRP Part A, p. 3).

NB Power's Load Forecast and Existing Supply Options

NB Power projects its peak demand will grow by 0.5 percent per year on average for the next 25 years, shown as the top orange line in Figure 1 below (NBP 5.01, 2017 IRP Part A, p. 79). With Energy Smart NB program activities, NB Power expects to reduce the peak load by 621 MW by 2042 (NBP 5.01, 2017 IRP Part A, p. 79). This reduced load due to the Energy Smart NB program is presented as the lower line in the figure below.

Figure 1. Effects of Energy Smart NB on load forecasts and resource requirements



Source: NBP 5.01, 2017 IRP Part A, Figure 37, p. 80.

As indicated by the downward arrows in Figure 1, NB Power expects to see expirations of two existing power purchase agreements (PPAs) and retirements of several existing power plants from 2025 through 2040. Table 5, below, shows a detailed summary of these PPAs and power plants in chronological order by type of resource.

Table 4. Summary of expected retirement of PPAs or power plants

Resource Type	Retirement Year	Details of PPA or Power Plants
PPA	2025	Grandview (95 MW)
	2027	Bayside (277 MW)
Power plants	2026	Grand Manan diesel CT plant (29 MW)
	between 2027 to 2032	One generating unit (112 MW) at Mactaquac hydro station
	2031	Millbank/Ste Rose diesel combustion turbine (CT) (496 MW)
	2040	Point Lepreau nuclear plant (660 MW)
	2041	Belledune coal plant (467 MW) and Coleson Cove oil plant (972 MW)

Figure 1 also shows the timing of expected resource shortage. For example, NB Power expects to see a shortage of supply resources starting in 2027 if it does not implement the Energy Smart NB program. By implementing the Energy Smart NB program as planned, NB Power can push back that resource shortage by four years to 2031.

NB Power's New Supply Options

The deferral of the resource shortage year essentially means that NB Power can avoid or defer the need to build new power plants. The 2017 IRP describes an "Integrated Plan" that incorporates the Energy Smart NB program's impact on the need to build approximately 590 MW of new supply resource options between 2027 and 2041 (NBP 5.01, 2017 IRP Part A, Figure 38, p. 81).

More specifically, this Integrated Plan avoids building a 412 MW natural gas combined cycle (NGCC) plant in 2027 and a 175 MW PUR plant in 2040. It also defers building a 99 MW unit at Millbank/Ste Rose from 2031 to 2041 (see Table 5 below for details).[8]

Table 5. Impact on supply resource mix of integrating Energy Smart NB

FY Ending	Integrated Plan	Supply Plan
2018	Energy Smart NB (621 MW) through 2042	
2019		
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)
…		
2027		NGCC (412 MW)
…		
2031	Millbank / Ste Rose CT (3 x 99 MW)	Millbank / Ste Rose CT (4 x 99 MW)
2032		
2033	Mactaquac Hydro life achievement	Mactaquac Hydro life achievement
….		
2040	Lepreau nuclear replace-in-kind (660 MW)	Lepreau nuclear replace-in-kind (660 MW) PUR (175 MW)
2041	NGCC (3 x 412 MW) Millbank / Ste Rose CT (2 x 99 MW)	NGCC (3 x 412 MW) Millbank / Ste Rose CT (99 MW)
Total PVRR (2017$)	$24.6 B	$25.7 B
NPV (2017 $)	$1.1 B	

Source: NBP 5.01, 2017 IRP Part A, Figure 38, page 81.

According to NB Power's analysis, the total present value revenue requirement (PVRR) for the Integrated Plan is $24.6 billion ($2017), while the total PVRR for a plan that excludes an Energy Smart NB program ("Supply Plan") is $25.7 billion (NBP 5.01, 2017 IRP Part A, Figure 38, p. 81). The difference is $1.1 billion—a substantial benefit expected to result from Energy Smart NB. Part of this benefit also results from avoided energy production due to Energy Smart NB. This avoided energy production represents approximately 2,300 GWh of annual cumulative energy savings by 2042 (NBP 5.01, 2017 IRP Part A, Figure 33, p. 70).

8 Embedded Generation represents renewable energy based distributed generation. LORESS stands for locally owned renewable energy projects that are small scale.

In addition, NB Power's analysis estimated GHG emissions and performed sensitivity analyses of different variables such as fuel prices, load, energy efficiency, solar, and GHG regulation.

The results of NB Power's various sensitivity analyses are summarized in the table below. The High Energy Efficiency sensitivity resulted in a decrease in PVRR, while the Extreme Energy Efficiency sensitivity resulted in a slight increase in PVRR. The GHG regulation sensitivities results were markedly larger; the two carbon dioxide (CO_2) cap sensitivities projected sizable GHG reductions ranging from 17 to 31 percent at an increased cost of 2–3 percent. The Federal GHG Regulation sensitivity analysis yielded a 29 percent reduction in GHG emissions with a 10 percent increase in cost.

Table 6. Selected NB Power IRP sensitivity case results

Sensitivity Case	Change in PVRR ($ billion)	GHG Emissions Reduction (Mt)	Reference
High Energy Efficiency	−0.2	0.3	NBP5.01, 2017 IRP Part A, page 93
Extreme Energy Efficiency	−0.1	0.4	NBP5.01, 2017 IRP Part A, page 93
Medium Solar Penetration	−0.1	0.1	NBP5.01, 2017 IRP Part A, page 94
High Solar Penetration	−0.2	0.1	NBP5.01, 2017 IRP Part A, page 94
CO_2 Cap: 3.0 Mt	0.5	0.6	NBP5.01, 2017 IRP Part A, page 95
CO_2 Cap: 2.5 Mt	0.8	1.1	NBP5.01, 2017 IRP Part A, page 95
Federal GHG Regulation	2.5	1.0	NBP5.01, 2017 IRP Part A, page 96

4.2. The Role of NB Power's IRP

In New Brunswick, the *Electricity Act* requires NB Power to file an IRP at least once every three years with government and with the Energy and Utilities Board. It also assigns the Executive Council as the authority to approve or reject an IRP, request changes to the plan, or request additional information from the NB Power before approval. The *Electricity Act* also explicitly requires the inclusion of demand-side management (DSM) and energy efficiency plans in the IRP (Electricity Act, Part 6, Division A (Planning), Section 100).

The *Electricity Act* further defines the IRP as a crucial component for developing other utility plans and setting rates. Specifically, the *Electricity Act* states that the 10-year strategic, financial, and capital investment plan "shall not be inconsistent with the latest IRP approved or deemed to be approved" (Part 6, Division A, Sec 101(3)). The 10-year plan includes a schedule of each capital project by the utility at or above $50 million (Part 6, Division A, Sec 101(1)(a)). Further, the *Electricity Act* states that IRP is an important component for consideration for the Board's order or decision on the utility's revenue requirements when "approving or fixing just and reasonable rates" (Division B (Electricity Services), Sec 103(7)).

These requirements for the IRP process defined in the *Electricity Act* clearly place the IRP as a vital vehicle to assess and develop rigorous long-term resource plans that enable NB Power to identify resources and solutions to improve its long-term financial status and reduce and stabilize electricity rates. For example, NB Power recognizes the benefits of Energy Smart NB program in the IRP as follows:

"[Energy Smart NB] provides a benefit to NB Power through immediate fuel cost savings and through lower capital requirements in the long term by reducing the need for new supply in the future. This, then, provides indirect benefit to all customers by ensuring low and stable rates" (NBP 5.01, 2017 IRP Part A, page 65 to 66).

4.3. Limitations of NB Power's IRP Analysis

Resource Optimization

The dynamic programming module PROVIEW used in the 2017 IRP has the capability of optimizing resource selection to find the least-cost plan in terms of total present value cost (NBP 5.01, 2017 IRP Part A, page 79). However, the results of the IRP's sensitivity analyses reveal that some resources, especially energy efficiency and solar PV, are not optimized. Rather, they appear as fixed resources with amounts that do not differ even if key assumptions are changed. The Company confirmed this in response to discovery requests (NBP (NBEUB) IR-83 and IR-198).

For example, sensitivity expansion cases that increase costs of supply-side resources such as the "All Capital + 25%" case and the "Gas and Market prices +25%" case find the same amount of load reduction from the Energy Smart NB program as the Energy Smart NB program under the Integrated Plan. Further, the "High Load Forecast" case identified the same amount of renewable energy resources as the rest of the cases, including the Integrated Plan case (NBP 5.02, 2017 IRP Part B, page 202 to 204). Given that the RPS target is set at 40 percent of the load by 2020, higher load forecasts should increase the level of RPS requirements on an absolute basis.

Analysis of GHG Legislation

The most important limitation of NB Power's IRP analysis is its treatment of the impact of GHG legislation. While NB Power did analyze the impact of GHG constraints in the IRP, this was only as part of its sensitivity analyses, and the sensitivities did not consider options for increasing the implementation of energy efficiency and renewable resources.

The Integrated Plan is used as the "reference case" of the IRP, therefore it should reflect the most likely electricity industry conditions that are expected at the time the IRP is prepared. In the Integrated Plan the Company assumes that there will not be any GHG constraints within the study period. This is clearly not an accurate assumption of the most likely conditions in New Brunswick.

New Brunswick's Premier joined with other Canadian First Ministers to adopt the *Pan-Canadian Framework on Clean Growth and Climate Change* on December 9th, 2016 as mentioned above (Canada, 2016). Carbon pricing is central to this framework, along with other complementary climate actions such as building codes and standards (Canada, 2017, page 2). The province is now committed to introducing a carbon pricing mechanism during the current session of the legislature, according to the first annual report on the implementation of the framework (Canada, 2017, page 37). In December 2017 the provincial government introduced legislation that would adopt the federal government's approach to addressing climate change (Environment and Local Government, 2017). These recent developments clearly indicate that GHG constraints should be modeled in the reference case in the IRP, because GHG constraints will be a part of the most likely future scenario.[9]

The Company's decision to model GHG constraints only as a sensitivity case is especially problematic because of its methodology for modeling energy efficiency and renewable resources. All of the cases in the IRP assume the same level of energy efficiency and renewable resources as in the Integrated Plan. In other words, the energy efficiency and renewable resources are not optimized in the sensitivity cases, and no additional energy efficiency or renewable resources are used in the sensitivities. Consequently, the sensitivity cases do not account for those GHG-free resources that are best suited for mitigating the costs of GHG legislation.

A modeling approach that properly accounts for carbon pricing and optimizes energy efficiency and renewable resources would certainly choose significantly larger amounts of those options. Carbon charges will increase the fuel and operating costs of many existing generation facilities, and limit the ability to repower or build new fossil-fueled generation capacity. It is also possible that the Belledune plant would need to be retired by 2031, which would require a large amount of low-GHG or GHG-free resources to replace it.

The Company's approach to modeling GHG constraints in the 2017 IRP dramatically reduces the study's usefulness. The Integrated Plan does not provide an accurate estimate of the Company's costs because it does not reflect the likely costs of GHG legislation. In addition, the GHG sensitivities significantly overstate the Company's costs because they do not account for the potential for energy efficiency and renewable resources to reduce those costs. Further, the IRP does not provide an accurate depiction of the amount of cost-effective energy efficiency and renewable resources available to the Company.

Analysis of Avoided Transmission and Distribution Costs

NB Power made it clear in its response to an interrogatory by the Board that "[o]nly the incremental primary benefits (fuel and purchased power and capacity deferral) were considered in the energy efficiency scenarios" and that "[t]he additional benefits associated with avoided T&D costs and other non-energy benefits were not included in the analysis" (NBP (NBEUB) IR-198). This is a critical omission in NB Power's IRP analysis which results in underestimation of the benefits of energy efficiency and other Energy Smart NB programs. It also results in overestimation of the PVRR calculations for each scenario.

The magnitude of T&D benefits can be quite large. For example, avoided T&D benefits could have value of more than $100 per kW-year depending on the type of investments. This value can be translated into about 3 cents per kWh—very similar to the typical cost of DSM programs, using NB Power's own

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[9] The IRP could include sensitivities with less stringent or no carbon regulations, to see how the results would compare with the expected carbon regulations in the reference case.

projection of DSM performance.[10] As a reference point, a study by Synapse Energy Economics for the Public Service Commission of Mississippi reviewed avoided costs for T&D for over 20 utilities across various states and one Canadian province. The study found the T&D costs range from about $40 per kW-year (US $2013) as the 25th percentile of reported values to $128 per kW-year (US $2013) at the 75th percentile (Synapse, 2014, 28–29).

Analysis of Other DSM Benefits

DSM programs provide other benefits that are not accounted for in the Company's IRP, including:

- Avoided costs of compliance with RPS requirements: New Brunswick's RPS has a target to achieve 40 percent of in-province electricity sales from renewable energy resources by 2020. DSM and Energy Smart NB programs reduce overall electricity sales, or load. In doing so, they reduce the cost of complying with the RPS by reducing the amount of renewable energy resources needed (NESP, 2017, 53).
- Avoided credit and collection costs: Low-income DSM programs in particular help customers reduce their energy bills and avoid their late or non-payment issues. The utility costs to deal with these issues include costs of notices and support provided to customers in arrears, costs associated with shutting off service and turning it back on, carrying costs associated with arrears, and costs of writing off bad debt (NESP, 2017, 53).
- Risk avoidance benefits: Vermont reduces the cost of energy efficiency programs by 10 percent to account for the net risk benefits of energy efficiency. As another approach, the Northwest Power Conservation Council (NWPCC) explicitly estimates risk avoidance values based on a stochastic analysis in its IRP modeling (Synapse, 2012, 49).

Given that these benefits, plus the avoided T&D benefits, are not accounted for, the Board should recognize that the 2017 IRP understates the full potential for cost-effective energy efficiency resources.

4.4. Recommendations

We recommend that the Board direct NB Power to properly account for compliance with relevant federal and provincial GHG legislation in all future IRPs. All IRPs should fully account for the most likely and most accurate estimate of future costs of complying with GHG constraints, because these constraints will clearly have significant implications for many elements within the IRP.

We also recommend that the Board direct NB Power to file at the time of the next rate case a revised 2017 IRP that properly accounts for the anticipated federal and provincial GHG constraints. The Federal GHG regulation sensitivity included in the 2017 IRP does not provide the necessary information to assess the impacts of GHG constraints, especially because this sensitivity does not account for increased energy efficiency, demand response, or renewable resources. Nor does it optimize the Company's portfolio of

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[10] Assuming a DSM load factor of 38 percent based on NB Power's data from "LF2016 - DSM.xlsx" (NBP 1.38, Appendix T, LF2016 - DSM.xlsx)

resources in response to the proposed new carbon charges. NB Power should file a revised IRP in the next rate case because the Company and the Board should not wait three years before assessing the implications of this critical industry development.

We also recommend that the Board establish IRP guidelines to direct how the Company conducts IRPs and makes decisions on which resources to implement. Experience in other jurisdictions indicates that clear and comprehensive regulatory guidance and oversight is necessary for successful IRP practices and outcomes (RAP 2013).

The IRP guidelines should ideally be developed through a separate proceeding. Alternatively, the guidelines could be developed as a part of the Company's next rate case filling. Either way, the process should allow for meaningful stakeholder input in the drafting, discussion, and approval of IRP guidelines.

We recommend that the IRP guidelines should address at least the following IRP topics:

1. The purpose of integrated resource planning. This should include a discussion of legislative, regulatory, and company goals that help define the IRP.

2. Definitions. This should include definitions for all of the key terms used in the guidelines, in order to avoid ambiguity or confusion.

3. Reporting requirements. This should describe all of the information that the Company should file in order to allow for a comprehensive and timely review of the IRP, by the Board and by interested stakeholders.

4. Assessment of the existing system. This should require each IRP to include a quantitative assessment of all the Company's resources and facilities, including all relevant information on customers, generation resources, transmission and distribution facilities, distributed energy resources, purchased power agreements, and more.

5. Forecasts. This should require each IRP to include comprehensive forecasts of all the key modeling inputs, such as load forecasts; fuel price forecasts; forecasts of naturally occurring distributed energy resources; forecasts of future environmental constraints; and more. This should also require each IRP to include alternative forecasts (e.g., low, middle, and high) with associated probabilities, for the purpose of developing sensitivity analyses.

6. Assessment of future supply-side resources. This should require each IRP to include a comprehensive assessment of all future supply-side resources, including new generation; upgrades or repowering to existing generators; new purchased power agreements; plant retirements; and transmission and distribution projects or upgrades.

7. Assessment of future distributed energy resources. This should require each IRP to include a comprehensive assessment of all future distributed energy resources; including energy efficiency; demand response; distributed generation, storage, electric vehicles, and more.

8. Portfolio development. This should require each IRP to include a suite of portfolios that assess a wide range of possible futures. It should identify appropriate techniques for computer modeling; for optimizing supply-side resources; for optimizing distributed energy resources; for modeling carbon constraints; for developing scenarios; for accounting for uncertainties; and for developing sensitivity analyses.

9. Criteria for selecting resources and portfolios. This should require each IRP to identify all the relevant costs and benefits of each resource and each resource portfolio, including avoided energy; avoided generation capacity; avoided transmission costs; avoided distribution costs; avoided line losses; avoided costs of environmental compliance; and more. This should also identify the criteria that the Company should use to determine the optimal, or preferred, resources and resource portfolio. These criteria should include the present value of revenue requirements; financial impacts (debt and equity); rate impacts (short-term and long-term); environmental impacts, and more.

10. Action plan. This should require each IRP to describe all the actions that the Company will undertake to implement the preferred resource plan and other elements of the IRP.

11. Regulatory process. This should describe the regulatory process necessary for each IRP, including filing timelines; the Board's review of each IRP; the criteria for the Board's review of each IRP; the potential for the Board to require revised IRPs; and more. It should also describe the process that will be used to allow for meaningful stakeholder input in the drafting, discussion, and review of each IRP.

We also recommend that the Board establish energy efficiency and demand response guidelines. These should be developed within or in concert with the IRP guidelines. Energy efficiency and demand response guideline are discussed in more detail in Section 6.4.

5. ENERGY SMART OVERVIEW

Energy Smart is the umbrella term for NB Power's investments in grid modernization (Smart Grid), DSM (Smart Habits), and product/service development (Smart Solutions) (NBP (NBEUB) IR-152).

- Smart Habits is NB Power's term for its initiatives to help customers save energy and money through changes in behavior. It includes conservation, energy efficiency, and demand response programs.
- Smart Grid encompasses initiatives and investments in technologies, processes, and systems to improve the efficiency, reliability, and flexibility of the power grid. It includes AMI, Distributed Energy Management System (DEMS), and Digital Communications Network.
- Smart Solutions houses NB Power's initiatives to increase revenue and offset reductions in sales as a result of adoption of distributed generation and DSM. It includes solar products, electric vehicle (EV) charging, smart homes, and other new business ventures (NBP (NBEUB) IR-152).

Table 7 provides a summary of the capital and OM&A costs that the Company is requesting for the fiscal year 2018/19, including the portion of the total that each comprises. The Smart Grid budget is the largest part of the total, primarily because it includes the budget for the proposed AMI.

Table 7. Energy Smart Budgets (millions $)

	2018/19 Budget	Percent of Total
Smart Habits	23.2	26%
Smart Grid	57.4	64%
Smart Solutions	9.3	10%
Total	90.0	100%

As discussed in Section 2, NB Power faces a number of challenges. It needs to reduce debt and maintain low rates while faced with low sales growth, rising costs, and increasing pressure to reduce GHG emissions. Energy Smart programs have an important role to play in helping the Company to cope with several of these challenges.

- By reducing demands on the power grid, Smart Habits programs can postpone the need for new generation capacity past 2027, and allow retirement of Belledune by 2030. As generally one of the least expensive resources, energy efficiency in particular can reduce electricity system costs.
- Both Smart Grid and Smart Solutions programs, if well designed, can enable greater penetration of distributed resources and reduce GHG abatement costs.
- By providing new revenue streams, Smart Solutions programs have the potential to allow NB Power to improve its debt/equity ratio.

Importantly, the full benefits of programs such as these can only be realized if they are part of the IRP process. As an example, if an IRP does not incorporate efficiency resources in load planning, a utility may overbuild costly generation capacity and cost ratepayers more than necessary. Energy efficiency and demand response can avoid or defer the need for new infrastructure, but only with proper planning and forecasting practices in place.

6. SMART HABITS

Smart Habits includes NB Power's conservation, energy efficiency, and demand response programs (NBP Response to NBEUB IR-152). The budget for conservation and energy efficiency is about 90 percent of the total DSM portfolio budget, while demand response accounts for about 10 percent (NBP 1.50, DSM Plan 2018/19-2020/21, p. 17, 24).

A thorough review of energy efficiency and demand response program should analyze (a) program designs, including customer sectors served and end-uses addressed; (b) program budgets; (c) program savings; and (d) program cost-effectiveness. In order to conduct such a review, all the relevant information should be clearly provided in the efficiency and demand response plans. These topics are addressed below for historical activities and for the planned activities, for energy efficiency and demand response programs separately.

6.1. Energy Efficiency Programs

Energy Efficiency Programs to Date

Table 8 provides a summary of the 2016/17 actual program spending, savings, and cost-effectiveness.

Table 8. 2016/17 Efficiency Program Spending, Savings, and Cost-Effectiveness

Program	Spending ($millions)	Savings (GWh)	Savings (MW)	Cost-Effectiveness (PACT) [11]
Residential: Retrofit + Direct Install	1.8	1.6	0.5	1.0
Residential: Home Energy Reports	1.4	4.1	0.9	0.2
Residential: Ductless Heat Pumps	3.8	7.9	6.3	2.2
Residential: Smart Habit Products	3.1	13.6	2.7	2.5
Commercial: Building Retrofit	1.2	7.0	1.0	4.1
Commercial: LED Streetlights	4.9	5.0	0.3	2.7
Commercial: Small + Med Bus Direct Install	0	0.0	0.0	N/A
Industrial: Small + Med Prescriptive	0	0.0	0.0	N/A
Industrial: Large Custom	0	0.0	0.0	N/A
Total Energy Efficiency	16.2	39.1	11.8	2.5
Enabling*	0.7	N/A	N/A	N/A
Total Including Enabling	16.9	39.1	11.8	2.0

Note: Enabling budget supports both energy efficiency and demand response. Source: 31-NBP (NBEUB) IR-49 Attachment - Historical DSM Results.

[11] The Program Administrator Cost Test compares the lifetime benefits that NB Power (and its customers) will derive from implementation of demand-side management (energy efficiency or demand response). It typically includes DSM benefits

NB Power's historical energy efficiency portfolio included the Commercial Building Retrofit, LED Streetlights, Ductless Heat Pumps, Home Energy Reports, Residential Retrofit and Direct Install, and Energy Efficient Product Rebates programs. Although the portfolio covered a range of end-uses and sectors in general, a high portion of savings—over 50 percent of annual MWh savings—is associated with lighting measures in the existing portfolio (NBP Response to NBEUB IR-53).

Table 9 shows planned versus actual spending and savings for the program year 2016/17. Overall spending was 18 percent lower than budget that year. Variances between planned and actual spending have been even more drastic for individual programs, notably residential Ductless Heat Pumps, as well as all commercial and industrial programs.

Table 9. Planned Versus Actual Spending and Savings, Energy Efficiency, FY 2016/17

Program	Spending Planned ($millions)	Spending Actual ($millions)	GWh Savings Planned	GWh Savings Actual	MW savings Planned	MW savings Actual
Residential: Retrofit + Direct Install	3.8	1.8	6.8	1.6	3.0	0.5
Residential: Home Energy Reports	1.7	1.4	16.1	4.1	3.7	0.9
Residential: Ductless Heat Pumps	1.8	3.8	4.1	7.9	0.4	6.3
Residential: Smart Habit Products	1.9	3.1	8.0	13.6	2.4	2.7
Commercial: Building Retrofit	0.8	1.2	3.2	7.0	0.4	1.0
Commercial: LED Streetlights	7.6	4.9	6.2	5.0	1.4	0.3
Commercial: Small + Med Bus Direct Install	0.9	0	1.6	0	0.2	0
Industrial: Small + Med Prescriptive	0.2	0	0.4	0	0.1	0
Industrial: Large Custom	1.1	0	9.6	0	1.2	0
Total Energy Efficiency	19.9	16.2	55.9	39.1	12.8	11.8
Enabling*	1.9	0.7	N/A	N/A	N/A	N/A
Total Including Enabling	21.8	16.9	55.9	39.1	12.8	11.8

Note: Enabling budget supports both energy efficiency and demand response. Source: NBP 1.56, Appendix AG i. DSM Plan 2016-17 Actuals, p. 4.

In 2015/16 and 2016/17, NB Power achieved annual incremental savings of approximately 24 GWh and 39 GWh respectively (31-NBP (NBEUB) IR-49 Attachment—Historical DSM Results). These savings levels represent approximately 0.2 percent and 0.3 percent of sales in the province.[12] NB Power fell short of achieving its energy savings targets in the 2015/16 to 2016/17 period, realizing only 75 percent of its

associated with avoided energy, avoided capacity, avoided transmission and distribution capital and operating costs, and others. The cost effectiveness screening is discussed further in Section 6.6, below.

[12] Sales data are from NBP (NBEUB) IR-51 a) 1. Referenced Table Appendix AA: Table 6 and NBP (NBEUB) IR-39 a) ii. Referenced Section Appendix AA i.

overall planned GWh savings (NBP 1.50, DSM Plan 2018/19-2020/21, p. 13). NB Power attributes this shortfall to the delay in implementing the new commercial and industrial programs, primarily due to the reallocation of budget to accommodate high demand for the Ductless Heat Pump program (NBP Response to NBEUB IR-47). Table 9 shows that savings (GWh and MW) varied markedly from plan to actual for almost all programs. Changes in plan versus actual savings are directionally consistent with changes in budget to spending, but they are generally not proportional. That is, projected dollars per unit of savings (GWh) varied dramatically from the actual cost of the savings, in particular for the Residential Retrofit + Direct Install, Home Energy Reports, and Commercial Building Retrofit programs.

Despite falling short on savings, in 2015/16 and 2016/17 the energy efficiency portfolio has been cost-effective, with a program administrator cost test (PACT) ratio of 2.1. On the program level, only the Home Energy Reports and Residential Retrofit + Direct Install programs were not cost-effective over this period, meaning they had a benefit/cost ratio of less than 1.0 (NBP 1.50, DSM Plan 2018/19-2020/21, p. 13). According to NB Power, the low PACT ratio for Home Energy Reports (0.2) is due to program costs being incurred in a different time period from realization of benefits (NBP Response to NBEUB IR-50). With a PACT of 0.9, the Residential Retrofit program was slightly less than cost-effective. However, NB Power does not include some widely accepted avoided costs in its benefit-cost analysis, including avoided T&D. A Societal Cost Test would include additional benefits, including avoided carbon mitigation, other fuel, and water costs. If NB Power included more program benefits in its analyses, this program would likely have achieved a ratio above 1.0.

Proposed Energy Efficiency Programs

Table 10. Projected Efficiency Program Spending, Savings, and Cost-Effectiveness, 2018/19 to 2020/21

Program	Spending ($millions)	Cumulative Savings (GWh)	Savings (MW)	Cost-Effectiveness (PACT)
Residential: Retrofit + Direct Install	12.5	36	5.2	2.0
Residential: Home Energy Reports	6.9	38	5.2	0.9
Residential: Low Income Energy Savings	11.0	13	2.1	0.9
Residential: Smart Habit Products	4.5	64	6.3	1.7
Residential: New Homes	3.8	20	3.3	3.8
Commercial: Building Retrofit	7.4	57	4.7	3.0
Commercial: New Construction	0.4	1	0.1	4.1
Commercial: Small Bus Lighting	6.9	52	3.9	2.0
Industrial: Small + Med Prescriptive/Custom	5.5	16	1.9	3.4
Industrial: Large Custom/EMIS	11.7	156	9.4	3.2
Enabling*	5.7	N/A	N/A	N/A
Total	74.7	457	42.1	2.2

Note: Enabling budget supports both energy efficiency and demand response. Source: NBP (NBEUB) IR-41; DSM Plan p. 8.

NB Power's portfolio of planned programs addresses a range of market segments, including programs focusing on energy efficient products, new construction, and existing buildings. The programs also cover a wide range of potential participants in the residential, commercial, and industrial sectors. A comparison of program coverage in other jurisdictions with NB Power's proposed DSM portfolio, as presented in Table 11 below, shows that NB Power's triennial plan has good program coverage.

Table 11. Summary of energy efficiency program types implemented in the northeastern States and the Atlantic Canadian provinces

	US States						Canadian Provinces		
Program Type	**MA**	**ME**	**CT**	**VT**	**NH**	**RI**	**NS**	**NB**	**NF**
Residential									
New Homes	X		X	X	X	X	X	X	
Existing Home: Single Family	X	X	X	X	X	X	X	X	X
Existing: Multifamily	X	X	X	X		X	X	X	
Lighting	X	X	X	X	X	X	X	X	X
Product Replacement	X	X	X	X	X	X	X	X	X
Product Recycling	X			X	X	X	X		
Behavior	X		X	X		X	X	X	
Low Income									
New Homes	X			X					
Existing Home: Single Family	X	X	X	X	X	X	X	X	
Existing: Multifamily	X		X	X		X			
Commercial and Industrial									
New Buildings	X		X	X	X	X	X	X	
Small Buildings	X	X	X	X	X	X	X	X	X
Large Buildings	X	X	X	X	X	X	X	X	X
Large Customer Self-Direct	X			X					
Strategic Energy Management	X		X	X		X	X	X	
Retrocommissioning	X		X			X	X		
Industrial Processes	X	X	X	X		X	X	X	X
Products	X	X	X			X	X	X	X
Cross Sector									
Building Code and Appliance Standard Support	X			X		X	X	X	

Note: This table was developed mainly based on a Synapse Energy Economics' 2016 report entitled Starting Energy Efficiency Off on the Right Foot: Regulatory Policies to Support Successful Program Planning and Design *(EE IRAC) and updated with NB Power's current energy efficiency program filing.*

The portfolio addresses hard-to-reach customers, including low-income, small commercial, and small industrial customers. While there is no single program that focus exclusively on multi-family buildings, such buildings are addressed through the Commercial Buildings Retrofit program. Also, NB Power states that it is considering developing a different offering for residents of multi-family buildings (NBP Response to NBEUB IR- 37).

NB Power's portfolio of planned programs addresses a wide range of end uses. NB Power claims it does not know what portion of savings from the proposed portfolio will be associated with lighting measures, although historically this has been high (NBP Response to NBEUB IR-53). As proposed, most of the existing programs (excluding ductless heat pumps and LED Streetlights) would continue going forward

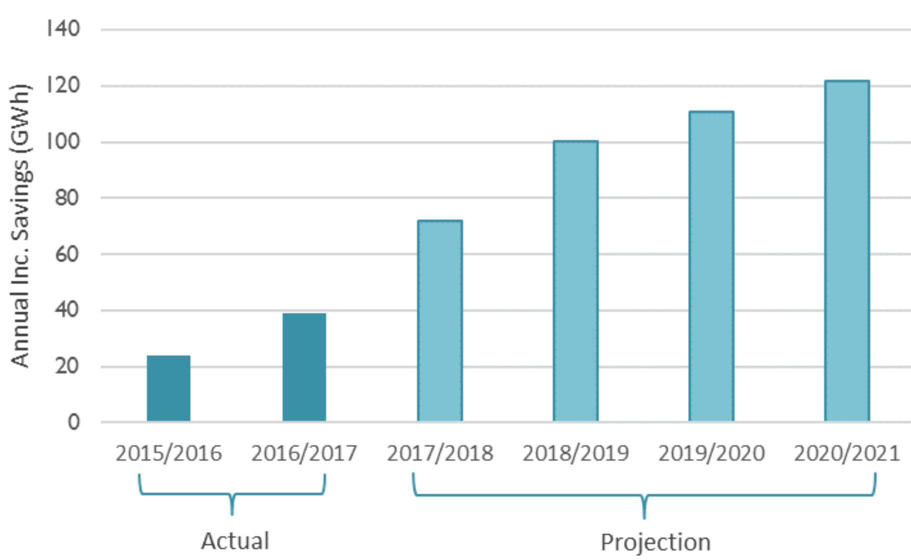
(NBP 1.50, DSM Plan 2018/19-2020/21, p. 8 and 13). This suggests that the share of savings from lighting may still be substantial in the proposed portfolio.

NB Power should consider whether alternative program designs would increase the reach of the programs or allow for greater cost efficiencies. Program modifications may be appropriate for the Low Income program. It has suffered from long waiting lists and administrative inefficiencies related to verifying continued customer-interest in the program. NB Power could explore providing a kit of low-cost measures for most applicants and reserving higher cost measures for applicants meeting specific criteria, such as those who exhibit very high energy use or receive bill payment assistance. As another example, for the Energy Efficient Products program, NB Power should investigate whether using upstream incentives rather than point-of-sale rebates would reduce costs, after taking into account higher free ridership rates.

The budget for energy efficiency programs in 2018/19 is $20.2 million (excluding enabling program costs). This is forecast to increase each year, up to $26.9 million in 2020/21 (NBP (NBEUB) IR-218 (a), NBP (NBEUB) IR-40).

For 2018/2019 through 2020/2021, NB Power is planning to expand its portfolio in terms of total annual savings and the scope of the programs. As shown in Figure 2 NB Power expects to increase energy efficiency savings to 120 GWh by 2020/2021. This level is approximately three times larger than the savings in 2016/2017 and represents 0.9 percent of projected sales in 2020/2021. Excluding the demand response programs, NB Power projects that of the annual DSM savings in 2020/2021, 42 percent will come from the residential sector, 23 percent will come from the commercial sector, and 35 percent will come from the industrial sector.

Figure 2. Historical and projected annual energy savings from NB Power's energy efficiency



Source: NBP 1.50 Appendix AA i. Three Year Demand Side Management (DSM) Plan 2019-2021; NBP 1.53 _Appendix AD - DSM 2019-2021 Model.xlsx; NBP (NBEUB) IR-51; NBP (NBEUB) IR-39.

NB Power assumes savings in the near term for programs that are still being designed, including Residential Home Retrofit + Direct Install, Residential New Construction, and Commercial New Construction (NBP Response to NBEUB IR-36). These three programs represent 7 percent of total energy efficiency portfolio energy savings in 2018/19 (NBP Response to NBEUB IR-41). Attributing this much savings to programs that are currently undeveloped may be unrealistic, depending on how and when NB Power rolls these programs out. Also, program designs should be more fully developed before requesting that costs be included in rates.

The proposed energy efficiency portfolio has a PACT ratio of 2.2, indicating that every dollar invested in DSM generates $2.2 in benefits. The individual programs are also largely cost-effective, with the exception of the Home Energy Report and Low Income programs. With PACT ratios of 0.9, the Home Energy Report and Low Income programs would likely show ratios above 1.0 if NB Power included more program benefits in its cost-effectiveness analyses.

Conclusions

In conclusion, the proposed energy efficiency programs are well-designed, cover a reasonable range of end-uses and customers, achieve a reasonable amount of savings, and are generally cost-effective. These programs would all be more cost-effective if the Company accounted for all the relevant benefits, particularly the benefit of reducing carbon emissions.

We are concerned, however, about the recent deviations between the planned and the actual program budgets and savings. As the efficiency programs expand over time, it will be important for NB Power to improve is program forecasting and implementation practices to reduce these deviations.

6.2. Demand Response Programs

Demand Response Programs to Date

In 2015/16 and 2016/17, NB Power implemented technical pilots in residential and commercial demand response. These pilots included smart thermostats and water heaters on the residential side, and a direct load control pilot on the commercial side (Appendix AA.i. p. 23 and 30).

NB Power did not achieve its historical MW demand savings targets for its demand response programs, because of the delay in implementing the new demand response programs (NBP Response to NBEUB IR-47). Demand response achievements are summarized in Table 12.

Table 12. Historical Demand Response Program Spending, Savings, and Cost-Effectiveness, Demand Response, 2016/17

Program	Spending ($millions)	Savings (GWh)	Savings (MW)	Cost-Effectiveness (PACT)
Residential: Smart Thermostat	0	0	0	N/A
Residential: Demand Response Alert	0	0	0	N/A
Residential: Time Based Pricing	0	0	0	N/A
Residential: Domestic Hot Water	0	0	0	N/A
Commercial: Large Commercial Fast DR	0	0	0	N/A
Total Demand Response	0	0	0	0
Enabling*	0.7	N/A	N/A	N/A
Total Including Enabling	0.7	0	0	0

Note: Enabling budget supports both energy efficiency and demand response. Source: NBP 1.56 Appendix AG i. DSM Plan 2016-17 Actuals, p. 4.

Table 13, below, shows planned versus actual spending and savings for the program year 2016/17.

Table 13. Planned Versus Actual Spending and Savings, Demand Response, FY 2016/17

Program	Spending Planned ($millions)	Spending Actual ($millions)	GWh Savings Planned	GWh Savings Actual	MW savings Planned	MW savings Actual
Residential: Smart Thermostat	0.9	0	0.8	0	2	0
Residential: Demand Response Alert	0.1	0	0	0	0.2	0
Residential: Time Based Pricing	0.1	0	0	0	0	0
Residential: Domestic Hot Water	0.8	0	0	0	1.5	0
Commercial: Large Commercial Fast DR	0.3	0	0.7	0	2.3	0
Total Demand Response	2.2	0	1.5	0	6	0
Enabling*	1.9	0.7	N/A	N/A	N/A	N/A
Total Including Enabling	4.1	0.7	1.5	0	6	0

Information and analysis about the benefits of the historical programs is lacking. In response to IRs, NB Power provided confidential reports on three historical demand response technical pilots: Smart Thermostats, Smart Water Heating, and Commercial and Industrial (NBP Response to NBEUB IR-185). These reports do not quantify the benefits of the historical pilot programs. Going forward, NB Power has partnered with National Research Council to study the benefits of load strategies in terms of economic optimization, ancillary services, and carbon emissions impacts (NBP Response to NBEUB IR-60). Also, NB Power released a Request for Expression of Interest to identify commercial and industrial direct load control solutions (NBP Response to NBEUB IR-60).

Demand Response Plans

Table 14. NB Power's Proposed demand response

Program	Spending ($millions)	Cumulative Savings (GWh)	Savings (MW)	Cost-Effectiveness (PACT)
Residential: Demand Response	4	1.2	15	0.2
Commercial: Demand Response	4	1.2	15	0.2

Source: DSM Plan, p. 23 and 30.

For demand response, NB Power proposes a residential program and a commercial/industrial program. NB Power plans to leverage its experience with the technical pilots it conducted in both the residential and commercial/industrial sectors in 2015/16 and 2016/17 for the proposed programs (NBP 1.50, DSM Plan 2018/19-2020/21, p. 30). However, NB Power has yet to flesh out demand response program designs. Specifically, incentive types and structures, customer eligibility, measure eligibility, and program guidelines have yet to be developed (NBP Response to NBEUB IR-36). While some information on outreach and marketing was provided regarding the soft launch of the commercial/industrial program, NB Power provided no information on outreach and marketing strategy for the residential program. These are all critical elements of the program design.

The proposed programs account for about 10 percent of the total DSM portfolio in terms of budget (NBP1.53, DSM 2019-2021 Model). The total requested budget is $8 million for both residential and demand response programs (DSM Plan, p. 23 and 30).

The proposed demand response programs account for about 30 MW of demand savings (NBP1.53, DSM 2019-2021 Model).

NB Power's benefit-cost analysis shows that the proposed programs are not cost-effective. The PACT for both the residential and commercial/industrial programs is 0.2, meaning that for every dollar invested, 20 cents of benefits are achieved for the electric system (NBP 1.50, DSM Plan 2018/19-2020/21, p. 37). Including omitted benefits in the cost-effectiveness analysis may improve the benefit/cost ratios. Demand response generally provides substantial avoided T&D benefits, which should be taken into account in the benefit/cost analysis.

Conclusions

In conclusion, the evidence presented by NB Power does not support the conclusion that the programs are in the best interests of ratepayers, particularly given the low projected benefit/cost ratios of the programs. We recommend that NB Power consider ways to make demand response more cost-effective, perhaps by targeting the most cost-effective energy uses and customer segments.

6.3. Evaluation, Measurement, and Verification

Evaluation Plan

NB Power proposes to update evaluation plans every three years (NBP 1.51, DSM EMV Plan 2019-2021, p. 2). Program developments that call for modification to the original EM&V plan would be handled during the program's planning phase, as needed (NBP Response to NBEUB IR-70).

The EM&V plan contains a reasonable amount of information on planned evaluation studies. For example, the plan provides information on study objectives, data collection methods, and the type of studies schedule to be conducted.

However, the plan misses some key information such as descriptions of evaluation study methodologies (except for a few programs), study-specific budgets, and information about evaluators (if known) or evaluator selection method.[13] In addition, the plan did not include any evaluation plans for several programs, including the residential and commercial new construction and demand response programs (NBP 1.51, DSM EMV Plan 2019-2021, p. 35-36; NBP (NBEUB) IR-71 and 80). According to NB Power, this is because program designs for these programs have not been developed yet (NBP (NBEUB) IR-71 and IR-80). NB Power should develop high-level evaluation plans for these programs as soon as its program designs are developed.

In response to our information request, NB Power provided some additional information on study methodologies (e.g., NBP (NBEUB) IR-68 through IR-80). For example, NB Power stated that study methodologies will be similar to the past studies for a few existing programs (e.g., Low Income, Energy Efficient Product Rebates, Commercial Building Retrofit Program) and provided the past studies as attachments. NB Power also provided a chart that summarizes all of the evaluation schedules over the next three years (NBP (NBEUB) IR-71 c).

NB Power proposed to allocate a budget of $1.5 million over a course of three years from 2018/2019 to 2020/2021, along with an additional $140,000 budget for EM&V activities not yet determined at this point (NBP 1.51, DSM EMV Plan 2019-2021, p. 1). This budget level represents about 2 percent of the total three-year DSM budget. NB Power acknowledges that this level is lower than best practices and that individual plans usually fall within the 3–5 percent range with an average of 3.5 percent in Canada and the United States as shown in Figure 3 (NBP 1.51, DSM EMV Plan 2019-2021, p. 11). Despite this concern, NB Power maintains this budget level seemingly because "all of the programs in market by the second year of this plan will have been evaluated at least once by the end of the plan" according to NB Power (NBP 1.51, DSM EMV Plan 2019-2021, p. 11).

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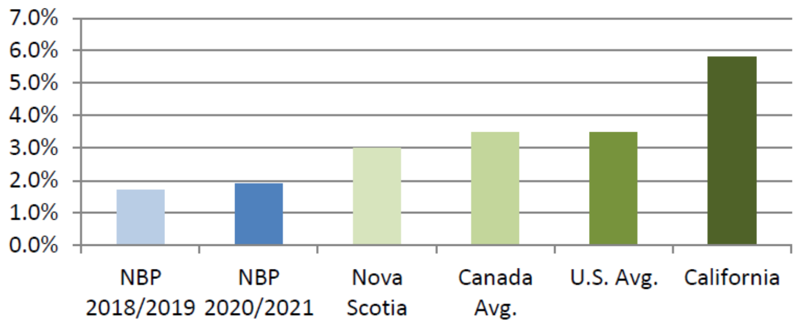
[13] A best practice report on program impact evaluation by the State and Local Energy Efficiency Action Network (SEE Action) titled "Energy Efficiency Program Impact Evaluation Guide" provide a list of key evaluation activities that need to be included in a portfolio cycle evaluation plan. The report is available at https://www4.eere.energy.gov/seeaction/system/files/documents/emv_ee_program_impact_guide_0.pdf

Figure 3. Share of Evaluation Budget over the Total Program Budget



Source: NBP 1.51, DSM EMV Plan 2019-2021, Figure 2, p. 11.

We concur with NB Power's concern. The State and Local Energy Efficiency Action Network (SEE Action) states in its 2012 report that "[w]hile it is difficult to generalize, common practice suggests that a reasonable spending range for evaluation (impact, process, and market) is 3% to 6% of a portfolio budget" (SEE Action. 2012, p. 7-14). When the size of the entire portfolio is large relative to other jurisdictions, an ideal evaluation budget can be set at the lower side of this range. Having mature and stable programs with sufficient evaluation history also helps keep the evaluation budget low. Collaborating with other jurisdictions on joint studies is another approach. However, given the relatively small size of NB Power's DSM program, a 2 percent evaluation budget may not be sufficient to conduct a sufficient number of robust evaluation studies or to cover other necessary studies. For example, the evaluation budget does not include any budget for studies on energy efficiency potential, net-to-gross ratio, and measure costs.

We also found the allocated budget per study may not sufficient.[14] NB Power allocated a budget of about $0.9 million to conduct about 20 studies[15] excluding budget for pilot program evaluation, rapid fire/intercept surveys, and plan administration. This results in about $50,000 per study on average. Other jurisdictions tend to spend more dollars per study. For example, Massachusetts—a leading state on energy efficiency—conducts robust evaluation studies, and typically spends more than $100,000 per study for impact and process evaluations (Massachusetts Program Administrators and EEAC Consultants. 2017).

NB Power indicated that it is not currently considering doing joint evaluation studies with neighboring jurisdictions because of differences in power rates, temperature regions, and heating system fuel types (NBP Response to NBEUB IR-71). In the future, NB Power should consider whether it makes sense to conduct joint evaluation studies in order to minimize the program evaluation budget.

Currently, there is no formal oversight of NB Power's evaluation plans and studies, except during a rate case. To ensure that study results are unbiased and robust, it is important to implement a transparent

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[14] NB Power did not develop study-specific budget, but provided an evaluation budget for each program.

[15] Impact, process, and market studies are counted separately.

and independent oversight process where an independent third party oversees selection of vendors, development of evaluation plans, and implementation of evaluation studies. For example, Massachusetts has a statewide energy efficiency collaborative called the Energy Efficiency Advisory Council (EEAC) composed of members that represent various sectors with expertise in energy efficiency. The EEAC consultants in Massachusetts work collaboratively with the program administrators to hire contractors, plan and implement the evaluations, and determine how results are applied to energy savings, incentive payments, and future program assumptions (Energy Futures Group et al., 2016, 55).

Technical Reference Manual

NB Power provided an update to its Technical Reference Manual (TRM) in Appendix AC (NBP 1.52, DSM Plan 2019-2021 Technical Reference Manual). A TRM provides a single, comprehensive resource on savings calculations for all programs in a jurisdiction. TRMs provide transparency regarding deemed savings estimates, a relatively simple and low-cost way of estimating energy efficiency savings (ACEEE, 2015, 9).

The scope of our review does not cover measure-specific data (e.g., whether certain savings estimates are reasonable or not). Instead, we conducted a high-level review of the TRM and concluded that NB Power's TRM contains sufficient amounts of data. The TRM clearly presents key information and data for energy efficiency measures such as measure description, energy and demand savings values and calculation formula, measure cost, and effective useful life, along with data sources. Measure-specific data should be investigated in a separate proceeding or forum with the type of thorough stakeholder review process typically done in many other jurisdictions. When used appropriately, a TRM "can be very useful for program planning purposes and can reduce M&V costs, create certainty, and simplify evaluation procedures" (SEE Action, 2012, 4-9). However, some TRMs draw on algorithms from other jurisdictions; these borrowed deemed values should be updated based on the results of the jurisdiction's own evaluation studies as soon as available. Also, there is a risk that TRMs become quickly outdated as technologies change.

For this reason, TRMs should be updated periodically (e.g., every year) to reflect best available information. NB Power does plan to update its TRM annually (NBP Response to NBEUB IR-81). However, there is no plan in New Brunswick for oversight of the TRM update, and other stakeholders should be afforded the opportunity to provide input. New Brunswick should establish a formal process for updating the TRM, with defined timelines, stakeholder roles, and an independent entity responsible for managing the update process.[16]

TRMs should be coupled with an EM&V plan that addresses any gaps identified through the TRM development process. For example, NB Power currently derives demand savings for efficiency measures using demand-to-energy consumption ratios from evaluations and literature reviews of similar

[16] For more information on the TRM update process, see Synapse, PEI EE, 2016.

jurisdictions. NB Power plans to refine initial assumptions as the pilot projects are completed and evaluated (NBP 1.51, DSM EMV Plan 2019-2021, p. 7).

Conclusions

NB Power's evaluation plan and other information provided in this rate case provide a reasonable amount of information for the Company's evaluation activities, but lacks some key information. The proposed evaluation budget may not be sufficient to conduct the planned evaluation studies. It is certainly not enough to cover other types of evaluation studies that are not included in the evaluation plan, but which may be needed for New Brunswick. While a measure-level review is outside of our scope, the TRM clearly presents sufficient information and data for energy efficiency measures. The TRM does not have any specific schedule for updates or does not have any formal process for a stakeholder review.

6.4. Opportunities for Future Plans

As described in Chapter 2, energy efficiency and demand response programs provide a significant opportunity for the Company to reduce revenue requirements, thereby assisting with both goals of maintaining low rates and reducing debt. And as described in Chapter 4, there remains a large opportunity for increasing energy efficiency and demand response programs to reduce electricity costs and defer or avoid the need for expensive new capital projects. Energy efficiency and demand response programs will become increasingly important, and increasingly cost-effective, once NB Power is assessed higher and higher carbon charges over time.

Consequently, NB Power should investigate all opportunities to expand upon its Smart Habits programs over time, with the goal of implementing all cost-effective efficiency and demand response programs. In this section, we provide recommendations for how the Smart Habits programs can be improved and expanded in the future.

Energy Efficiency

Energy efficiency program participation rates, budgets, and savings could be increased considerably over time. If carbon mitigation and other avoided costs were properly accounted for, then all of the energy efficiency programs would be more cost-effective. Moreover, the relatively high PACT ratio suggests that there may be additional efficiency resources that NB Power can tap before efficiency costs exceed benefits.

Regarding the potential for achieving more savings, there has not been a potential study completed since 2012. However, NB Power has not tapped even close to the remaining achievable potential. From 2013/14 to 2017/18 (projected), NB Power reports total savings of 142 GWh, as compared to Dunsky's estimate of 388 GWh per year in 2017 for base achievable potential (NBP Response to NBEUB IR-61; NBP Response to NBEUB IR-61 a) Attachment, slide 37; and NBP Response to NBEUB IR-85 Attachment). We recommend that NB Power complete a new potential study as planned. This study will reveal technologies and market segments where NB Power can expand its efforts. NB Power should continue to explore opportunities for non-lighting savings as the lighting market transforms.

Demand Response

We encourage NB Power to consider ways to further investigate demand response programs to explore ways to make them for successful and more cost effective. NB Power has identified some ways that it may be able to improve the cost effectiveness of its demand response programs. These include investigating an upstream approach with manufacturers to integrate load control devices into the product upon purchase, and concentrating the commercial/industrial demand response program budget in incentives, in order to send a stronger price signal to participants (NBP (NBEUB) IR-219).

Future Regulatory Policy and Guidance

Experience in other jurisdictions indicates that energy efficiency programs are most successful if they are supported by clear, comprehensive regulatory guidance and policies. As NB Power expands its Smart Habits programs it will be increasingly important for the Board to provide the Company with guidance regarding the key issues of program design, budgets, savings, cost-effectiveness, EM&V, and more. Further, as the potential costs and benefits of the Smart Habits programs expand, it will become increasingly important to allow stakeholder input regarding those programs.

Many states and provinces have established regulations or guidelines describing how energy efficiency programs should be planned for, reviewed, and implemented.[17] Establishing criteria and principles to comprehensively and appropriately evaluate DSM plans would significantly enhance the development of energy efficiency resources in New Brunswick.

Some of the key regulatory policy features that are particularly valuable in promoting successful energy efficiency resources include the following:

- Clear, stable, and long-term regulatory guidance and support.
- Robust stakeholder engagement, e.g., through a collaborative process or an energy efficiency advisory council.
- A policy mandate to implement all cost-effective energy efficiency, accompanied by a clear definition of what this means.
- Regulatory guidance on appropriate cost-effectiveness test(s) for screening efficiency programs and which costs and benefits to include.
- Guidance on proper estimation and presentation of avoided costs, including avoided energy, capacity, transmission, distribution, losses, and costs of compliance with environmental regulations.

[17] Attachment 2 provides the Rhode Island Least Cost Procurement Standards as an example of what is typically included in energy efficiency regulations or guidelines. Rhode Island is frequently ranked as one of the leading states in energy efficiency performance.

- Establishment of sound IRP practices and processes.
- Guidance on reasonable analysis and management of bill impacts, particularly where energy efficiency budgets are constrained due to concerns with rate impacts.

Further information on regulatory policy features to support implementation of energy efficiency is available in Synapse's Prince Edward Island energy efficiency report (Synapse, IRAC EE, 2016).

6.5. Recommendations

The 2018/2018 Smart Habits Programs

We recommend that the Board approve the energy efficiency programs, budgets, and savings targets proposed by the Company for the 2018/2019 year. The proposed energy efficiency programs are well-designed, cover a reasonable range of end-uses and customers, achieve a reasonable amount of savings, are generally cost-effective, and are consistent with legislative goals, Company objectives, and industry practices.

We recommend that the Board reject the demand response programs, budgets, and savings targets for the 2018/2019 year. The demand response program designs are not sufficiently developed and the proposed programs are not expected to be cost-effective even by the Company's analysis.

We recommend that the Board approve the current evaluation plan. NB Power's evaluation plan and other information provided in this rate case provide reasonable amount of information for the Company's evaluation activities, but lacks some key information.

Opportunities for Future Smart Habits Programs

We recommend that the Board direct NB Power to file in its next rate case a revised DSM plan that addresses the deficiencies identified in this report, particularly regarding the demand response programs, the program design descriptions, and the evaluation plans. The Company and the Board should not wait for three years to address these important deficiencies.

We recommend that the Board direct the Company to include in the revised DSM plan new demand response programs. The description of new demand response programs should (a) provide sufficient detail on program designs; (b) address the limitations identified in this report (e.g., by accounting for avoided transmission and distribution costs); and (c) demonstrate that the programs will be cost-effective.

We recommend that the Board direct the Company to file more complete program information in all future DSM Plans. This should include, for each program, the following:

- incentive design and covered measure types: dollar incentive levels or formulas for determining incentive levels, incentive strategy (early retirement or replace-on-burnout), description of how incentive level was determined relative to certain price points (e.g., incremental cost, total project cost, project payback, etc.), required efficiency and other specifications of measures

- marketing strategy: planned and potential outreach, marketing, advertising efforts and strategies
- target customers and customer eligibility: customer classes and income thresholds targeted by the programs, and requirements to participate
- annual budgets
- annual savings, lifetime savings, and peak demand savings: incremental and cumulative
- evaluation plans: budgets, type of evaluation, strategy, schedule (for individual programs and as a portfolio)
- demonstration of cost effectiveness: present value of costs, present value of benefits, total net present value benefits, and ratio, using a test that reflects the priorities of the province and best practices in resource valuation

We recommend that the Board direct NB Power to provide in all future DSM Plans the following additional pieces of information for each evaluation study: (a) high-level description of study approach/methodology, (b) budget for each program, (c) evaluator name (if known) or evaluator selection method. We also recommend that the Board direct NB Power to allocate additional budget to future evaluation plans, to ensure that they are sufficiently robust to support increased energy efficiency and demand response implementation.

Future Regulatory Policy and Guidance

We recommend that the Board notify the Company that the Board places a high priority on the Smart Habits programs, because of their ability to reduce costs, reduce bills, defer new capital investments, reduce the debt-to-equity ratio, and reduce the costs of GHG constraints. In order to demonstrate that the Board places a high priority on the Smart Habits programs, we recommend that the Board direct the Company to achieve all cost-effective energy efficiency and demand response resources.

An additional way for the Board to demonstrate that it places a high priority on the Smart Habits program is to establish guidelines defining how energy efficiency and other distributed energy resources should be planned for, reviewed, and implemented in the future.

We recommend that the Board develop guidelines for distributed energy resources. The DER guidelines should ideally be developed through a separate proceeding. Alternatively, the guidelines could be developed as a part of the Company's next rate case filling. Either way, the process should allow for meaningful stakeholder input in the drafting, discussion, and approval of IRP guidelines. The establishment of DER guidelines should be coordinated with the establishment of IRP guidelines, either by preparing them in parallel or including the DER guidelines within the IRP guidelines.

We recommend that the DER guidelines address at least the following topics:

1. Program planning and review processes. This includes establishing a continuous cycle encompassing planning, implementation, evaluation, and reporting. This includes incorporating standardized data table templates and metrics for plans and reports, to facilitate comparisons of plans to reports and performance from year to year.

Program design. This includes describing the breadth of customer types and end use markets to be targeted by energy efficiency programs. The portfolio should include all "core" energy efficiency programs, to include, at a minimum, the following: residential (new construction, single-family retrofits, and products and appliances); low income (new construction, single-family retrofits, and multi-family retrofits); commercial and industrial (new construction, small businesses, large businesses prescriptive, large businesses custom, and multi-family buildings). This also includes reflecting long-term policy goals, and program designs that are consistent with those goals.

Cost-effectiveness screening. This includes specifying that the Company should seek to implement all cost-effective distributed energy resources. This includes describing how avoided costs should be presented and calculated. Avoided costs should include avoided energy, capacity, transmission, distribution, losses, and costs of compliance with environmental regulations. This should also incorporate state-of-the-art practices, including the principles and methodologies in the National Standard Practice Manual (NESP, 2017). This also includes specifying inputs and methodologies for assessing rate and bill impacts of DER programs.

Multi-year planning and savings targets. This includes identifying energy efficiency program budgets and savings targets in three-year plans.. Program budgets and targets should be updated on an annual basis. This also includes guidance for NB Power to ramp-up savings targets by an additional 0.4 percent of retail sales each subsequent year, to reach savings levels consistent with achieving all cost-effective energy efficiency in the province.

Cost recovery and budgeting. This includes establishing rules for NB Power to shift funding across programs within a sector as needed to meet the needs of customers in a timely manner. The guidelines should set limits regarding the amount that can be shifted (e.g. less than 25 percent) within a program year without Board approval. This should also include requirements for tracking categories of spending and budgets to allow for comparison with other jurisdictions, e.g. costs of saved energy or savings as a percent of retail sales.

Stakeholder input. The guidelines should establish an ongoing, permanent DER stakeholder process to allow for meaningful input on program design, implementation, and evaluation. Members of the collaborative should include customers from different sectors and of different sizes, consumer advocates, energy efficiency experts, and environmental groups. Stakeholders should have unfettered access to information, fair ground rules for deliberations, and recourse to adjudicated proceedings or other regulatory intervention. The process should allow for independent DER experts to advise the stakeholders, to be funded through the DSM portfolio budget.[18]

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[18] For examples of effective stakeholder processes, see information on the Massachusetts Energy Efficiency Advisory Council at http://ma-eeac.org/; the Rhode Island Energy Efficiency and Resource Management Council at https://rieermc.ri.gov/; and the Connecticut Energy Efficiency Board at https://www.energizect.com/connecticut-energy-efficiency-board.

Evaluation. The guidelines should establish a formal process for updating evaluation plans and the TRM, with defined timelines, stakeholder roles, and an independent entity responsible for managing the update process.

7. Smart Grid

Smart Grid investments and activities form a core component of NB Power's plans for the test year, and of the Company's vision throughout the planning period reflected in the 10-Year Plan, the Strategic Plan, and the IRP. NB Power rightly recognizes that new technologies can be deployed throughout its operations to improve customer service and cost-effectiveness. The Company recognizes that these new technologies will require changes in processes and utility approach throughout its organization. Smart Grid also provides enabling technology to improve the delivery of Smart Habits and Smart Solutions programs.

Smart Grid has many components, but the largest by far is the proposed combined investment in AMI and the Digital Communications Network that will enable the collection of data from the new meters. These two pieces of technology and the associated process changes are combined in NB Power's AMI capital investment proposal. Because the Board has the explicit responsibility to approve or disapprove of this investment in this case, we have focused our report on evaluating this proposal. We conclude this section with a brief examination and recommendations regarding the non-AMI portions of NB Power's Smart Grid program.

7.1. Advanced Metering Infrastructure

NB Power proposes to deploy advanced meters throughout the province. It also proposes to implement the necessary communication system to collect the data from those meters and the software tools (meter data management system, or MDMS) to effectively use the data and integrate it with existing systems (such as billing). Meter deployment would begin in 2019 and extend for three years. NB Power identifies that this deployment will cost $153.8 million, which is in excess of the $50 million threshold for Board review and approval of a capital project under subsection 107(1) of the *Electricity Act*. Of the total cost, $62.2 million is the cost of the meters and their installation; $42.5 million of capital investment will pay for the communications system, integrations with existing systems, meter data management, procurement services, and pre-engineering costs; and $49 million will support operations and maintenance costs associated with the deployment (including the $16 million cost of the social benchmarking energy conservation program).

NB Power has presented a cost-benefit analysis for the AMI deployment which shows that the project would result in a net cost, on a present value basis, to NB Power ratepayers between now and 2033. The present value cost in its analysis is $122.7 million, while the benefits total $121.4 million. NB Power has quantified benefits from:

- an energy conservation program utilizing social benchmarking ($28.9 million);
- avoided meter replacement costs ($23.5 million);
- reduced manual meter reading costs ($19.6 million);
- reduced meter visits including for connection and disconnection ($10.3 million);

- increased meter accuracy ($5.8 million);
- a portion of the savings from a future conservation voltage reduction (CVR) program ($5.3 million);
- the remaining net book value of the AMI investment at the end of the study period ($5.3 million); and
- seven other smaller impacts which each provide $1.1 million or less in present value benefits.

NB Power has assumed for its analysis that each new meter will have a 15-year life. We believe this assumption strikes an appropriate balance between the possible hardware life of the meters themselves and the likely rapid pace of technological advancement that may spur a faster replacement cycle than for traditional meters.

Costs of the AMI Proposal

NB Power partnered with Nova Scotia Power, Emera Maine, and Tampa Electric Company for a joint procurement process. This allowed NB Power to share the cost of the procurement process itself (including for the services of the consultants which helped the consortium with its procurement), draw on the joint expertise and experience of the four utilities, and take advantage of economies of scale associated with a larger number of meters and communications infrastructure procured together. This procurement process appears to have been successful, and NB Power has received competitive and appropriate bids for the system. We believe it is unlikely that NB Power could have achieved this cost for AMI deployment if it had undertaken this process alone.

We have examined AMI business cases filed by other utilities in order to evaluate whether the all-in cost that NB Power proposes is reasonable. We will make comparisons on a non-discounted basis because AMI costs tend to be clustered at the start of analysis period and it allows us to compare without worrying about different discount rates. NB Power's non-discounted proposed cost is $153.8 million. None of these comparison utilities are deploying the same set of technologies as NB Power proposes. Rather, they include some additional items but exclude some of what NB Power proposes. However, they do indicate that NB Power's proposed costs are reasonable.

- BC Hydro filed a smart meter infrastructure plan in 2010 to serve its 1.9 million customers. It included both metering and communication systems (as well as investments in in-home devices and targeted at energy theft reduction). The total proposed cost was $930 million, including reserve and contingency (BC Hydro, 2010, p. 10). Scaled to the size of NB Power's proposed deployment, the equivalent cost would be $173.8 million. Subtracting the reserve and the conservation tools, the equivalent cost would be $145 million.
- AEP Ohio filed in 2013 to deploy 894,000 advanced meters. It also included associated communications infrastructure and circuit control technology, along with distribution circuit automation and Volt-VAR optimization for a number of circuits. The cost listed was $US465 million (AEP Ohio, 2013, p. 10). Scaled to the size of NB Power's proposed deployment and using an exchange rate of 1.33, the equivalent cost would be $245.6 million.

- Consolidated Edison (New York) filed in 2015 to deploy 3.5 million electric meters and 1.2 million gas communications modules for a total cost of $US1.285 billion (New York Public Service Commission, 2016, p. 4 and 6). Scaled to the size of NB Power's proposed deployment and using an exchange rate of 1.33, the equivalent cost would be $129 million. This assumes that gas meters and electric meters have the same cost. In practice, however, the gas deployment is only of communications modules to add to existing meters. We can provide an upper bound on a scaled cost by counting only electric meters. This results in a scaled comparison cost of $173.3 million.

While the initial costs of NB Power's proposal appear reasonable, we disagree with NB Power's treatment of future costs in its cost-benefit analysis. NB Power chose to conduct the analysis for a 15-year period that ends just as its AMI meter fleet is approaching the end of its life. NB Power's current meter fleet has an average age of 13 years and an expected lifetime of 22 years and 7 months (domestic meters) or 24 years and 6 months (power meters) (NBP (NBEUB)IR-31). Therefore, at the start of the analysis period, NB Power has a meter fleet with an average of at least 9.6 years of remaining life. At the end of the analysis period, in contrast, NB Power's meter fleet will have a remaining life of just 1.3 years: the average meter will be 13.7 years old compared with an expected lifetime of 15 years (NBP (NBEUB) IR-31).

One way to see this cost is that the net book value of NB Power's meters (and associated hardware, software, MDM, etc.) will fall from $18.5 million to $12.5 million from the start to the end of the analysis period.[19] (This includes the write-down of the existing meters.) NB Power counts the remaining value of $12.5 million as a benefit of the AMI deployment, instead of counting the reduction in net book value by $6 million as a cost. Correcting this results in an increase in the net cost of AMI deployment by $7.8 million. In other words, remove the $5.3 million benefit and replace it with a $2.5 million cost.

Accelerated depreciation of the existing meters also creates a net cost to ratepayers. Instead of paying off these sunk costs over the remaining hardware life of the meters (an average of more than nine years), NB Power is asking ratepayers to pay for them over the next five years. Since we don't have the full data for a depreciation study, we have had to be necessarily simplistic in estimating these costs. Nevertheless, we have calculated them as having a present value of roughly $3.8 million.

Benefits of the AMI Proposal

We have examined NB Power's claimed benefits from AMI deployment. Most appear reasonable, and we do not doubt that AMI would deliver substantial benefits to the province's ratepayers. However, three claimed benefits of AMI are problematic: the social benchmarking conservation program, CVR, and the remaining book value. The claimed remaining book value benefit was discussed above; we believe it is more appropriate to recognize the decline in net book value as a cost.

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[19] For consistency, we are using the net book value of meters as identified in the AMI Investment Rationale ($18.5 million), rather than the higher value ($20.1 million) identified in NB Power's Response to NBEUB IR-160. The implied base case (no AMI deployment) is that the net book value of the meters will stay level as meters age out and are replaced consistently.

Social benchmarking

NB Power's largest claimed benefit from AMI deployment is $28.9 million in present value benefit from "kWh Reduction with Customer Programs." These customer programs are described and modeled entirely as "social benchmarking" programs similar to the Oracle Home Energy Report program that NB Power currently uses to engage more than 120,000 customers regarding their energy use. As NB Power is currently demonstrating, AMI is not necessary for implementing a social benchmarking-based conservation program. NB Power has assumed that AMI will enable substantial additional savings but has not presented evidence to support that claim. In fact, the evidence indicates that additional savings from AMI may be small to nonexistent.

First, let us examine the calculation of NB Power's claimed benefit. NB Power assumes that more than 312,000 customers (consisting of about 300,000 residential customers and 12,000 general service customers) will reduce their consumption by an average of 141 kWh/year as a result of the program (0.9 percent savings), with 30 Watts of peak savings per participant. This results in net savings at generation of 46.7 GWh per year, and almost 10 MW on peak. Once multiplied by the avoided costs of energy and peak demand, this results in savings in excess of $3 million per year, and a present value through 2033 of $28.9 million. NB Power assumes that it will be able to implement such a program for a cost of $3.50 per year per participant, adjusted for inflation. The 2022 cost is $1.1 million, and the present value of the cost over the analysis period is $9.5 million. The claimed net benefit from the program is therefore $19.4 million.

The Home Energy Report program that NB Power proposes to implement from 2018 to 2021 is projected to reduce energy use by 38.3 GWh and peak by 5.2 MW. The program aims to engage 170,000 customers with mailed reports at a cost of $2.3 million per year ($13.50 per participant). NB Power explains that it "took care to not double count the benefits attributed to the Home Energy Report in the 2019–2021 DSM Plan and the potential future social benchmarking program attributed to the AMI business case. Since it is assumed that a full roll-out of the AMI meters is not expected until after 2021, the next DSM Plan would include an enhanced Home Energy Report program with the benefits of AMI included (i.e. lower cost and/or higher impact) or an alternative social benchmarking program that leverages AMI" (NBP Response to NBEUB IR-172(c)).

There are two ways to interpret NB Power's proposed conservation program and associated value. The first is that NB Power is proposing to replace its existing Home Energy Reports program with the program characterized in the AMI business case. This interpretation is supported by NBP (NBEUB) IR-172(c), in which the Company uses the lack of overlap in time between the proposed program and the current program as evidence that savings are not double-counted. The problem with this interpretation is that without AMI, NB Power could continue to provide the same level of social benchmarking conservation program it does today, or expand that program to serve the larger universe of customers envisioned by the AMI proposal. Therefore, the only net benefits attributable to AMI must be those that are additional to the non-AMI case. Setting aside the possibility to expand the non-AMI program, the difference from the proposed DSM plan would be 8.4 GWh energy use reduction per year (46.7−38.3=8.4) and 4.8 MW on peak (10−5.2=4.8), along with a reduction in program cost from $2.3 million to $1.1 million per year. Such a dramatic reduction in program cost would require further justification. Regardless, these net benefits do not equal NB Power's claimed net benefits from an AMI-associated conservation program. If program replacement is the correct interpretation, NB Power must recalculate the net benefits for inclusion in the cost-benefit analysis.

The second interpretation is that the claimed benefits are *in addition to* the baseline case of Home Energy Report continuation. This means that NB Power would be claiming that the addition of AMI will allow the Company to more than double the savings from social benchmarking, while reducing its cost per customer served. If we take NB Power's analysis in this light, the Company is claiming that with AMI it will be able to save 85 GWh per year (46.7+38.2=85), along with 15.1 MW on peak (10+5.2=15.1).[20] The cost would be about $3.4 million per year (2.3+1.1=3.4). This would be a remarkable program: It would be inducing customers to reduce their consumption more than 1.6 percent every year at a cost per customer of less than $11 (about 20 percent less than the current program). NB Power has claimed in NBP (NBEUB) IR-172(b) that AMI will increase program impact and reduce costs, so we must seriously evaluate a claim that AMI will result in dramatic improvements in savings and program costs.

NB Power states that "the social benchmarking program used in the AMI business investment rationale model was simply an example of a potential program that could be offered" (NBP (NBEUB) IR-172(e)). NB Power also repeatedly claims that it has been conservative in the development of assumptions regarding the costs or benefits of the AMI proposal (NBP 11.02, Revised Evidence, p. 196 and 198).

The other social benchmarking programs that NB Power cites by providing their evaluations in Appendix Y (NBP 1.45, NBP 1.46, and NBP 1.47) do not reliably deliver annual savings at the level that NB Power assumed:

- The evaluation of Pacific Gas & Electric shows savings between 0.9 percent and 1.5 percent (NBP 1.45, Appendix Y ii, p. 43).
- The evaluation of AEP Ohio shows average savings of 1.99 percent across cohorts that included only above-average energy use customers, low-income customers, or customers with AMI. AMI customers saved 1.6 percent (NBP 1.46, Appendix Y iii, p. 13).
- The evaluation of Ameren Illinois shows savings of between 0.92 percent and 1.55 percent across programs that included only above-average energy use customers who are also dual-fuel (electric and gas) customers (NBP 1.46, Appendix Y iii, p. 81-82).
- The evaluation of Commonwealth Edison shows average savings of 1.13 percent across a number of cohorts; the only AMI-specific cohort has savings of 1.21 percent (NBP 1.47, Appendix Y iv, p. 11).
- The evaluation of San Diego Gas & Electric shows average savings of 1.9 percent (NBP 1.47, Appendix Y iv, p. 64).

[20] Difference is due to rounding.

- The evaluation of Puget Sound Energy shows average savings of 3.0 percent among a cohort of dual-fuel (gas and electricity) customers that use more than 80 MMBtu of energy per year (NBP 1.47, Appendix Y iv, p. 102 and 104).

Of the six programs that NB Power examined, three produce savings below NB Power's assumption, one is equal, and two exceed it. NB Power has not yet completed an evaluation of its own non-AMI Home Energy Report program to see how it compares with these examples.

The programs that NB Power highlighted in its submission generally started with or continue to serve primarily high-use households. As the authors of the Commonwealth Edison evaluation say, "HER programs have a well-documented pattern that higher usage customers achieve higher savings from the program" (NBP 1.47, Appendix Y iv, p. 9). NB Power's assumed AMI-enabled program would serve all but 7 percent of its customers (4 percent control group and 3 percent opt-out), so it would include both low-usage and high-usage customers. This means that, all things being equal, we should assume that NB Power's near-universal program would underperform compared with these other programs.

In NBP (NBEUB) IR-172(f), the Company makes an adjustment of 20 percent for "active" available participants. This adjustment was not made in the calculation of the AMI business case. If it were made, the claimed net cost of AMI deployment would likely increase by about $3.9 million (a 20 percent reduction in the conservation program's $19.4 million net benefit). This adjustment would, however, be a positive corrective step to account for the challenge that home energy report-type programs have with move-out, seasonal customers, and other mechanisms of attrition from the treatment group. If NB Power has 322,833 residential customers, processes over 43,000 move-out requests per year, and serves more than 18,000 seasonal customers (NBP (NBEUB) IR-171), the actual universe of eligible households for participation in a home energy report program is likely closer to 260,000. After accounting for opt-out and the need for a control group, residential participation would likely be limited to about 240,000. This is about 20 percent lower than assumed in the business case.

While NB Power claims that AMI would "[i]ncrease program impact by providing more timely, relevant data to customers on actions they can take to reduce consumption" (NBP (NBEUB) IR-172(b)), NB Power has provided no evidence of the extent of this impact in New Brunswick or elsewhere. The only home energy report evaluations NB Power presented that compare AMI to non-AMI customers (the AEP Ohio and Commonwealth Edison evaluations) are either imperfect (the AEP Ohio evaluation doesn't have comparable groups with and without AMI) or they show a larger effect among non-AMI households (the Commonwealth Edison evaluation shows 1.68 percent effect for non-AMI households in the same "wave" as the AMI households that had a 1.21 percent effect).

Summary of social benchmarking critique

NB Power's largest claimed benefit for AMI is poorly justified and very likely overstated. While claiming that the program is conservatively defined, NB Power has in fact asked the Board to rely on a large and uncertain source of value in order to bring the AMI deployment's benefits close to its costs. Net benefits are overstated by at least 20 percent due to lower participation, as NB Power has effectively admitted in NBP (NBEUB) IR-172(f). That alone would be a roughly $3.9 million overstatement. In addition, NB

Power has either misstated the baseline (ignoring the existing Home Energy Report program) or claimed quite aggressive energy and cost savings while claiming conservatism.

Conservation Voltage Reduction

Utilities can deploy CVR without AMI. However, AMI assists with CVR by providing voltage sensors at every customer's location. This both increases the quantity of data available to optimize CVR and avoids the cost of deploying separate voltage sensors. It is appropriate for the AMI deployment analysis to include a share of the benefits of CVR, and we do not object to the share that NB Power has assumed. However, NB Power has not committed to CVR and has no specific plan for its implementation (NBP Response to NBEUB IR-174(a)), so shared benefits from CVR are too uncertain to include in this cost-benefit analysis.

In addition, NB Power has not sufficiently justified the need to wait for seven years after the AMI meters are deployed to begin CVR (NBP 11.02, Revised Evidence, p. 200). In fact, in the calculation of the value of CVR for the purposes of the AMI Investment Rationale (Exhibit NBP 1.48), NB Power assumes that CVR benefits will begin in 2025, which is only four years after meter deployment is complete. The Company asserts that CVR is dependent on other technologies "such as Supervisory Control and Data Acquisition (SCADA), Distribution Management Systems (DMS), AMI, and Digital Communications Networks" (NBP (NBEUB) IR 174(b)). These other technologies are all envisioned as deployed by 2021. We are encouraged that NB Power, in NBP (NBEUB) IR-174(b), has indicated an intention to incrementally deploy CVR. NB Power should develop a plan for CVR, including a detailed timeline that relates to the timelines for the deployment of enabling technologies. It should submit the plan to the Board at the next rate case so that the benefits can be appropriately characterized and attributed to the AMI proposal and to evaluation of other enabling technologies.

AMI Should Be Implemented in a Way that Empowers Customers

AMI has the potential to increase customer engagement and optimization of their energy use. It is also an enabling technology for third-party service providers who can provide innovative services to utility customers. For example, the "Green Button" initiative has established standard data formats for the sharing of smart meter data with service providers.[21] Metered energy use data is fundamentally the customer's data: Its collection is only possible because of the customer's financial commitment to metering, and the customer should have control of that data to share as she sees fit. We are concerned with NB Power's response when asked about sharing data with third parties. NB Power revealed an expectation that data would be shared with the *Company's* consultants and contractors, but it failed to commit to making data available for *customer-designated* third parties (NBP Response to NBEUB IR-168). The Board should require NB Power to allow customers and their designees access to time-resolved usage data through standard formats and protocols.

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[21] See http://www.greenbuttonalliance.org/ for information about the Green Button Alliance, a partnership of utilities, technology providers, and government agencies.

NB Power has proposed that customers who opt out of having an AMI meter be charged a fee that corresponds to the costs that their choice causes. While this is appropriate and can be done fairly, we are concerned that NB Power's lack of specificity on the method of calculating that fee could result in unexpected results for the Company, the Board, and customers. NB Power says that it will "develop an opt-out policy, procedures, and rates in Year 1 of the AMI project" (NBP (NBEUB) IR-26). It does not know whether the fee will differ based on whether the customer retains an analog versus an AMR meter, or whether a customer who opts out will be asked to pay for some or all of the AMI deployment to their fellow customers. In other words, will they pay the direct or net cost of their choice? The Board should require NB Power to provide a proposed opt-out fee structure, with example or estimated values, prior to approval of the AMI investment.

AMI Should Be Coupled with Time-Based Prices and Reviewed in the Next Rate Case

As calculated by NB Power, the proposed AMI investment would have a present value net cost to New Brunswick ratepayers of $1.3 million. AMI would provide some unquantified benefits as well, and NB Power implies that these unquantified benefits plus the quantified benefits will outweigh the costs, and thus the Board should approve the capital investment.

However, we have shown that NB Power has significantly understated the costs and overstated the benefits of its AMI proposal. We suggest several adjustments to the Company's analysis in order to address some of our concerns above. In particular, NB Power should:

- Account for loss in net book value of meters: $7.8 million.
- Account for accelerated depreciation: $3.8 million.
- Adjust for overstated net benefits from AMI-enabled social benchmarking: At least $3.9 million, up to $19.4 million.
- Not include the benefits from CVR until NB Power presents an implementation plan: $5.3 million.

These adjustments turn a nearly break-even proposition into a net cost to ratepayers of roughly $22.1 to $37.6 million.

NB Power could make the AMI initiative more cost-effective by making concrete the non-quantified or insufficiently concrete benefits they have claimed. In particular, NB Power should:

- Produce a plan for CVR to make those claimed savings real, as discussed above, and
- Propose time-based pricing that empowers customers and enables substantial system-level savings.

Time-based pricing could provide considerable benefits to both participating customers and the body of ratepayers as a whole. In its Evidence, NB Power provided an example of the net benefit from implementation of a critical peak price rate in which only 19,000 customers participated: $5 million present value (NBP 11.02, Revised Evidence, p. 200). If NB Power has to offset a net cost of between $17 to $32 million (presuming that the CVR benefits are subsequently justified), net benefits from time-based pricing would need only exceed this small-group example by a factor of 3.5 to 6.5.

As an example that this kind of benefit is possible, consider the possible impact of a peak-time rebate rate design as the default rate for all residential customers. Instead of 19,000 participating customers, there would be nearly 323,000. If one-third of customers opted out of participating at all, and the remaining customers only changed their behavior by half as much as NB Power's example critical peak price program, the net benefit of the program could be around \$28 million.[22] Data from dynamic pricing implementations indicate that peak time rebate programs are less effective than critical peak price programs, but only by about a factor of two (Faruqui and Sergici, 2013, p. 6). That effect may itself be due to differences in the ratio of prices used in the rate design rather than to fundamental differences in customer response.

In sum, it might be possible to develop and implement an AMI initiative that turns out to be cost-effective. However, NB Power has not provided the evidence for a cost-effective AMI initiative in this docket. In order to develop and justify a cost-effective AMI initiative, the Company would at least have to first develop time-based rates that could deliver significant benefits, as well as the quantitative details justifying those benefits.

Recommendations

We recommend that the Board reject the Company's AMI proposal. The Company's own analysis suggests that the proposal is not cost-effective, and that analysis suffers from some fundamental flaws. Given the Company's goals of maintaining low and stable rates and reducing debt, spending so much money on an initiative that is not essential and not cost-effective is unwise. Furthermore, the absence of a concrete proposal for time-base rates makes it very difficult to assess one of the most significant potential benefits of AMI.

We also recommend that the Board direct the Company to refile a new AMI proposal in next year's rate case. The new AMI proposal should correct for the limitations described in this report, and it should identify opportunities for achieving net benefits from AMI.

It is our understanding that NB Power and the NBEUB have deferred consideration of time-based pricing until the next rate case for FY 2019–20. This provides an opportunity for NB Power to file in the next rate case a complete and revised AMI proposal which:

- addresses the analytical issues we have identified regarding meter book value and accelerated depreciation;
- corrects the deficiencies we have detailed in the analysis of AMI impacts on social benchmarking or other conservation programs;
- provides a plan for CVR earlier than seven years after AMI meter deployment; and
- couples detailed analysis and proposals for time-based rates with the AMI infrastructure necessary to support them.

[22] \$5 million × 323,000 / 19,000 × 2/3 × 1/2 = \$28.3 million

We recognize that rejecting the AMI proposal at this time, while inviting an improved proposal next year, is not without cost. We do not take lightly the disruption that delaying a project can cause. However, in purely financial terms, NB Power estimated little net cost in the revenue requirement from a one-year delay, because the avoided capital cost would be balanced by personnel costs as staff remain mobilized without beginning the project (NBP Responses to NBEUB IR-124 and NBEUB IR-238). These staff may be productively used during that year improving the AMI proposal for resubmission. A one-year delay in the AMI capital investment would not substantially impact the long-term pursuit of the Company's debt-equity target.

7.2. Non-AMI Smart Grid Proposal

Overview

NB Power has been working closely with Siemens since 2012 on grid modernization and smart grid. NB Power's smart grid activities are diverse, and no other new activity approaches the size and scale of the proposed AMI and Digital Communications Network rollout. However, the Company's other smart grid technology plans are not small: Between 2019 and 2028 the Company plans to spend $139 million on capital to support them, while spending $111 million on AMI and Digital Communications Network (NBP 1.11, Appendix C I, p. 18).

The plan that NB Power is implementing in partnership with Siemens can be described as a set of activities to update the Company infrastructure in terms of its tools, operations, and approach. Take the "Smart Organization" domain as an example: This relates to core competencies in information and operational technology, cybersecurity, relations with stakeholders and the Board, and the procurement processes necessary to purchase wisely in the modern world. "Smart Asset and Work Management" is similarly focused on better performing the core activities of a Company such as maintenance and work management.

Recommendations

In general, the non-AMI initiatives of the Smart Grid proposal appear to be reasonable and consistent with industry practices, regulatory objectives, and the Company's long-term goals. Therefore, we recommend that the Board approve these non-AMI initiatives. However, given the magnitude and the important role of these initiatives, we recommend that the Board monitor them closely over time and provide guidance on their implementation.

First, NB Power should constantly evaluate the need, the costs, and the benefits of the non-AMI initiatives to ensure that they are prudent and that they are implemented as efficiently and cost-effectively as possible. Those elements that are non-essential and are not expected to produce net long-term benefits to customers should be carefully scrutinized.

Second, Smart Grid tools for integrating distributed energy resources must be well-coordinated with the planning and delivery of the Smart Habits and Smart Solutions programs. If the Board orders adjustments to the Smart Habits or Smart Solutions programs, the Company should also make any related adjustments in Smart Grid initiatives.

Third, NB Power should develop and provide the Board with more specificity regarding its Smart Grid initiatives. For example, Smart Network Operations will be engaged in laying the groundwork for CVR. We support NB Power investigating opportunities for cost-effective CVR, to pilot CVR, and to move to scale across the province. As we discussed above, we believe that NB Power needs a more detailed plan for CVR, and we recommend that the Board direct the Company to develop such a plan.

Fourth, NB Power should consider actively developing in-house expertise to provide a check on the Siemens' recommendations and reduce the need for Siemen's assistance as time goes on. The use of a broad and all-encompassing structure like the Siemens Compass means that the Company's long-term plan lacks specificity. It also means that there is relatively little transparency for the Board into the details of processes or decision-making that NB Power is implementing with Siemens's assistance. A deep integration with a consultant can be effective, but it can also leave the Company overly-dependent.

Finally, we highlight the importance of the Smart Organization project on cyber security and privacy. The goal of this project is to incorporate best practices for cyber security and privacy into tools and processes through the Company. This should include both operational cyber security (prevention of outside actors from impacting the delivery of electric service) and data security/privacy (prevention of the release of collected private customer or Company data). One challenge will be the development of security practices and protocols that keep data secure yet accessible to customers and their designated agents. We recommend that the Board consider opening a separate proceeding to establish regulatory guidelines for cyber security, data privacy, and customer access. Such a proceeding should allow for stakeholder input and collaborative development of common principles and approaches across all the province's electric and gas utilities.

8. Smart Solutions

8.1. New Brunswick Power's Proposal

Smart Solutions is NB Power's plan for delivering services that enable customers to manage their energy consumption and lower their bills. NB Power has several objectives in implementing Smart Solutions: mitigating the need to invest in new generation assets and/or power purchase agreements, reducing risk that traditional assets will be stranded, and developing new lines of business and streams of revenue. The goal of the latter is to offset declines in electric distribution revenues resulting from, for example, increases in adoption of distributed generation, energy storage, and energy efficiency (NBP 11.02, p. 204-205 and 210). By offering these services, NB Power may be able to increase revenues, which in turn may enable NB Power to achieve a more balanced debt-to-equity ratio.

Smart Solutions includes near-term investments with benefits accruing in later years. According to NB Power, the Smart Solutions plan has a benefit-cost ratio of 1.85 and results in a $1.1 billion decrease to the present value of revenue requirements over the 25-year term of the IRP (NBP Evidence, 2017, p. 205).

Ostensibly, NB Power's existing initiatives for water heating, exterior lighting, and EV charging fall under the Smart Solutions umbrella (NBP 11.02, p. 255, lines 25 to 26). In 2017 and 2018, NB Power plans to focus on entry into the markets for publicly accessible EV charging stations, smart home technologies, and solar solutions (NBP Evidence, 2017, p. 240). These initiatives are described further below:

- **EV chargers.** NB Power states that it must adapt to increasing adoption of EVs. EV adoption has not yet become widespread in New Brunswick but has seen substantial growth elsewhere (NBP 11.02, p. 210). NB Power plans to assess and subsequently launch EV charger business opportunities, such as in the residential, fleet, and workplace markets NBP 11.02, p. 260). Two of NB Power's initiatives are already underway: the SmartTwo EV Chargers and EV DC Level 3 Chargers (NBP 11.02, p. 226).
    - SmartTwo EV Charger program is for commercial and general service customers. Participating customers purchase the charger from AddÉnergie (a third-party partner) and incur all installation and operating costs. Any increases in revenues from this program to NB Power arise from increased electricity sales. There are currently approximately 77 Level 2 chargers in New Brunswick, 16 of which are owned by NB Power (NBP Response to NB EUB IR-184). Currently, there are plans to enable installation of 100 or more customer-owned Level 2 chargers (NBP 11.02, p. 240).
    - The public EV DC Level 3 charging program seeks to encourage EV adoption in the province by establishing a network of charging stations. It has a long-term objective of leveraging EV battery storage to provide energy back to the grid during peak times. The DC Level 3 chargers are located at strategic locations around the province (NBP (NBEUB) IR-184). Currently, there are 11 DC fast chargers province-wide, 10 of which are owned by NB Power (NBP (NBEUB) IR-184 (c)). This year, NB Power plans to expand company-

owned chargers with 15 new NBP-owned DC Level 3 chargers along major highways (NBP 11.02, p. 240).

- **Smart Home.** NB Power plans to offer a "revenue-based" Smart Home Package to customers. It includes rental of Wi-Fi enabled gateways, thermostats, light switches, and water heater energy monitors (NBP 11.02, 2017, p. 226 and 240). NB Power is currently reviewing the business model to take into account feedback during the "soft" launch of the service (NBP Response to NB EUB IR-190 (b)).
- **Solar.** A 2017 study by Dunsky Energy Consulting finds that NB Power has a large technical potential for full distributed solar deployment—in the range of 1.6 to 5 GW (NBP 1.41, Baseline and Solar Lease Study). This represents up to 80 percent of demand. Natural uptake of solar without NB Power programs is projected to result in 250 MW of installed capacity by 2040. The Dunsky report recommends that NB Power invest in solar development via a solar lease program to offset losses in sales (NBP 1.41, p. 6-7). A detailed solar business plan and associated project plans are under development (NBP Response to NB EUB IR-191 (a)).

In 2018 and 2019, NB Power will expand on the EV charger and smart homes initiatives, as well as on demand response initiatives (discussed in Section 6.2 of this report). In this period, it will also pursue new business areas, including deployments of solar and storage technologies and launch of a "safety-related and resiliency" product (NBP 11.02, p. 260).

The Company plans to develop its marketing and sales capabilities to further enable product deployment, integration, and support. In the evidence, NB Power describes its process for new product/service development and launch as involving "a progressive investment of time, effort and financial resources tested at stage gates." NB Power states that the governance mechanism associated with the process "allows investments to be curtailed as the product or service viability is considered throughout the progression" and "minimizes risk and strives for a balanced portfolio of, marketable and profitable, products and services over many customer segments or rate classes" (NBP 11.02, p. 256-259).

8.2. Discussion

The initiatives contained in Smart Solutions represent an innovative approach to reducing system costs and augmenting revenues in the face of declining sales. However, there are two important issues for the Board to be aware of: the potential for undermining the development of competitive markets and the potential risks of the various initiatives.

<u>Competitive markets</u>

Several of the Smart Solutions initiatives seek to provide services and products that could be provided by the unregulated competitors. NB Power has monopoly status in electricity distribution, and this status likely affords NB Power advantages in related markets as well. NB Power may have the ability to prevent other suppliers from entering these markets, e.g. by temporarily understating prices, by creating obstacles for competitive providers, or by using regulated activities to subsidize unregulated initiatives.

In its evidence, NB Power did not present arguments for why it should be permitted to offer these services and products, instead of competitive providers. Further, NB Power did not provide analyses of the impacts that NB Power's presence has or will have on the development of these markets (See, for example, NBP (NBEUB) EUB IR-190 (c)).

It may be appropriate for a monopoly firm or government agency to offer certain products and services that are or could be provided by a competitive market. The market has thus far had difficulty supplying some types of goods and services such as EVs and charging stations. Developing EV charging stations requires considerable up-front investment. A single publicly accessible EV charging station—which might easily be supplied by any number of third-party suppliers—would likely do little to encourage consumers to adopt EVs. On the other hand, a network of chargers, which would be more difficult for the market to develop, can better support widespread EV adoption. Yet even with these barriers, market entry does occur and should be encouraged. For example, NB Power expects that other entities will provide EV charging services as the number of EVs grows in New Brunswick. NB Power is even aware of third parties with plans to develop chargers in the province (NBP (NBEUB) IR-184 (c)). NB Power should be working with these third parties to identify the optimal locations for these chargers and to help make the business case for third-party chargers viable.

As another example, based on NB Power's discussions with solar installers and customers, NB Power reports that its entry into the emerging solar market may stimulate growth of this industry in the province (NBP (NBEUB) IR-191). Nonetheless, the justification for NB Power to directly provide services and products is generally not clear and has not been articulated in NB Power's evidence. Utilities can have a variety of roles in addressing market gaps, from facilitating third-party efforts to directly providing services or products. While there are market barriers for solar, programs that support the market have been highly effective in other jurisdictions, such as incentives to reduce up-front costs. Likewise, the market for home automation services is growing on a wider geographic scale, if not locally, with likely competition from online retailers. If suppliers are present in these markets, the justification for NB Power to enter these lines of business is less compelling.

Potential Risks

NB Power's evidence in this case does not demonstrate that the Company has fully accounted for the risks associated with these initiatives. For example:

- **EV chargers.** NB Power is generally aware of the impacts that EVs and EV charging have on the power system, including increases in electricity demand, operational risk, and the opportunity for energy storage in vehicle batteries. NB Power asserts that "environmental and economic forces are pushing increased adoption in other jurisdictions and the continued electrification of vehicles is inevitable – only the timing of the shift is uncertain" but admits that "New Brunswick-specific research [on adoption of electric vehicles] is not currently available" (NBP 11.02, p. 210). It is not clear that NB Power has investigated the local barriers to EV adoption, which may differ from the barriers experienced elsewhere. Such research could reveal how the barriers would best be addressed. Further, it is not clear how the cost-effectiveness of this effort can be determined without a baseline from which to measure increased EV adoption. Also absent from NB Power's evidence and responses is a comprehensive assessment of risks associated with the current or expanded EV charger program. Such risks may include underutilization of the chargers or investing in a standard that ultimately does not become the industry norm.

- **My Smart Home.** In the response to NB EUB IR-190, NB Power provides a high-level market plan for My Smart Home (NBP Response to NB EUB IR-190 (a) Attachment). While the confidential outlook for the program shows projected financial performance, no in-depth or quantitative analysis of risk exposure (e.g., counterparty risk, technology risk, etc.) has been presented (NBP (NBEUB) IR-190 (b)).
- **Solar initiative.** A Dunsky Energy Consulting study conducted for NB Power considered revenue impacts associated with different types of solar leases relative to a baseline (NBP 1.41, Baseline and Solar Lease Study). But the study did not consider risks associated with this business opportunity. A business plan should consider the potential and likelihood that negative outcomes associated with new business opportunities could overwhelm positive ones and ultimately place funds at risk, e.g. due to participant default on leases. NB Power stated that it does not yet have a business plan for solar (NBP (NBEUB) IR-191 (a)). The results of the confidential market analysis provided by NB Power raise questions about consumer interest in solar (NBP (NBEUB) IR-191 (a) and (c)).

If the Company expects to use these initiatives to generate revenues, it is important that it account for and minimize risks associated with greater costs, lower benefits, lower participation than expected, or greater competition than expected.

8.3. Recommendations

In general, the Smart Solutions initiatives appear to be reasonable and consistent with industry practices, regulatory objectives, and the Company's long-term goals. Therefore, we recommend that the Board approve these initiatives. However, given the magnitude and the important role of these initiatives, we recommend that the Board monitor them closely over time and provide guidance on their implementation.

We recommend that the Board direct the Company to provide more details on each of its Smart Solutions initiatives in future rate cases. First, the Company should provide on-going assessments of the competitiveness of each of the unregulated markets that it participates in. This should include studies on current market conditions, technological and other barriers to entry, customer demand, the number of competitors, and market potential for the product. This should also include analysis of the impacts that NB Power's presence will have on the development of the competitive markets, and a plan for interacting with and supporting competitive, third-party market participants.

Second, we recommend that the Board direct NB Power to provide in future rate cases more detailed business cases for each of the Smart Solutions initiatives. These business cases should include forecasts of costs, benefits, customer participation, and revenues; and should analyze and describe the major risks associated with each initiative (including, at a minimum, technology, counterparty, and price volatility risks).

9. PERFORMANCE METRICS AND REPORTS

9.1. The Role of Performance Metrics and Reports

Reducing costs and improving productivity are critical steps that NB Power must take to meet its goal of 20 percent equity while maintaining low rates. However, the current regulatory framework provides NB Power with little financial incentive to improve performance.

As discussed in Chapter 2, costs related to OM&A and depreciation and amortization are responsible for almost all of the increases in revenue requirements in the instant proceeding. Further, NB Power has a history of exceeding its budgeted or approved costs. These facts point to the need for greater cost containment measures, as well as the need to embrace all opportunities to reduce future revenue requirements through optimizing the resource mix.

In a competitive market, firms compete to provide high-quality products and services at prices lower than their competitors. This competition serves as a strong incentive for a firm to operate as efficiently as possible. Because utilities are monopolies, competition is largely absent and regulators are charged with ensuring that utility rates are just and reasonable. Regulators have therefore sought to simulate the incentives provided by the competitive market through other tools such as multi-year rate plans, financial incentives, benchmarking, and transparency.

In the case of investor-owned utilities, regulators often implement positive or negative shareholder incentives to encourage the utility to operate as efficiently as possible. This option is not available for publicly owned utilities. Instead, regulators may rely on performance metrics to provide greater transparency of utility operations and encourage the utility to improve efficiency and achieve policy goals.

The purpose of utility performance metrics is to provide the utility, the regulator, and interested parties a means of measuring in a transparent manner how a utility is performing in key areas that are critical to a well-functioning utility. Publicly available metrics can leverage regulatory and political pressure as an effective means of influencing utility management. This ensures that utility management is faced with the possibility of paying a political cost (or reaping a political reward) for changes in its performance.

Establishing performance metrics has the following effects:

- They provide a useful tool so that regulators can monitor a utility's performance and identify where progress is or is not being made.
- They help to make regulatory goals explicit and allow regulators to provide specific guidance on important state and regulatory policy goals.
- They allow regulators to focus attention in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.

- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization.

These same concepts can be applied in New Brunswick to ensure that NB Power has adequate cost containment incentives and delivers on the myriad initiatives that it proposes to undertake. While NB Power currently maintains a variety of performance metrics, the current metrics are relatively limited in how they are used to inform regulatory decisions. Therefore, we recommend building upon these metrics to help make NB Power's operations, productivity, and performance more transparent to the Board. This will help the Board encourage cost reductions while maintaining service quality.

9.2. Existing Performance Metrics and Reports

The Company's original evidence filed in this docket provides little information on existing performance metrics and how they are used. Based on information provided in subsequent discovery responses, it appears that NB Power has a host of existing performance metrics, apparently presented and used in several different forums. We summarize these below.

Key Performance Indicators

In Appendix AT, NB Power provides a summary of some of its key performance indicators (KPIs) as they pertain to its goals, objectives, and strategic initiatives (NBP 1.98, Appendix AT). These are summarized in Table 15. Appendix AT is not clear whether these are the only KPIs used by the Company.

In addition, NB Power prepares Executive Monthly Management reports that includes another set of KPIs (NBP (NBEUB) IR-246 (b)). These reports include the same strategic excellence areas as presented in Appendix AT (safety, customer, organizational, reliability, environmental). However, the KPIs presented in the Executive Monthly Management reports do not completely align with those in Appendix AT: some are included while some are missing. The Executive Monthly Management report is not clear on whether these are the only KPIs used by the Company. The Company notes that its performance measures and targets are reviewed annually as part of NB Power's Business Planning process, which would explain any differences between the KPIs presented in Appendix AT and in the Monthly Management reports (NBP (NBEUB) IR-246 (b)).

In addition, NB Power has prepared a corporate excellence plan that describes some of its KPIs. The most recent corporate excellence plan that we were able to find is the NB Power 2017/2018 Corporate Excellence Plan (CEP), which was filed as part of the Company's previous rate case (NBEUB IR-127, in matter 336 NB Power 2017/18 General Rate Application). The 2017/2018 CEP included the same strategic excellence areas as presented in Appendix AT (safety, customer, organizational, reliability, environmental). The KPIs in the 2017/2018 CEP do not completely align with those in Appendix AT: some are included while some are missing.

Table 15. NB Power key performance indicators

Strategic Excellence Areas	Key Performance Indicator
Safety Excellence	Days between high potentials
	All injury frequency rate
	Lost time injury severity rate
	Public/contractor contact with facilities
Customer Excellence	Customer uptake in Energy Solutions
	Customer satisfaction index
Organizational Excellence	Free cash flow
	Capital spending
	OM&A
	Net earnings
	Continuous improvement savings
Reliability Excellence	SAIDI
	SAIFI
	Hydro equivalent availability
	Belledune equivalent availability
	Nuclear equipment reliability index
	Nuclear capacity factor
	Capital expenditures
	Outage preparation readiness
Environmental Excellence	In-province energy reduction
	Annual peak hour demand reduction
	Reduction in internal energy use

In addition, the Energy Smart section of the original filing describes the top five KPIs of Energy Smart NB (NBP 11.02, pp. 241-241). These include: in-province energy reduction; annual peak hour reduction; product and service net income; conservation voltage reduction; and meter-to-cash operational savings. Additional information on these top five AMI KPIs is provided in NBP (PI) IR-47 and NBP (PI) IR-48 (c).

Benchmarking Reports

Since 2011, NB Power has benchmarked its performance against peer utilities in North America across seven categories of metrics, including reliability, costs, safety, customer satisfaction, and environmental performance. [23] These categories and the associated metrics are shown in Table 16 below, as described in NB Power's 2016 Benchmarking Report. NB Power provides these metrics in a report that summarizes the utility's performance over time compared to peer utilities.

[23] Customer satisfaction was not part of the original reports, but was introduced in 2014.

Table 16. NB Power benchmarking metrics

Performance Dimension		Metrics
1	Shareholder Performance	Return on Assets (ROA)
		Net Earnings as % of Revenue (ROR)
		% Debt in Capital Structure
		EBIT (Earnings Before Interest and Taxes) Interest Coverage
2	Cost Performance	NB Power 3-Year Total Energy Cost/MWh Delivered
		NB Power 3-Year Non-Fuel OM&A Cost/MWh Delivered
		NB Power 3-Year Fuel Cost/MWh Delivered
		NB Power 3-Year CapEx/PP&E
		Hydro 2-Year Generation Cost/MWh
		Hydro 2-Year Non-Fuel OM&A Cost/MWh
		Transmission 3-Year Total Transmission Cost/MWh Transmitted
		Transmission 3-Year OM&A Cost/MWh Transmitted
		Transmission 3-Year Sustaining Maintenance Capital Expenditures/Transmission PP&E
3	Safety	All Injury Frequency Rate
		Lost-Time Injury Severity Rate
4	Environment	SO_2 Emissions g/kWh
		NO_X Emission g/kWh
		CO_2 Emissions g/kWh
5	Customer Satisfaction	Customer Satisfaction Index
6	Reliability - Generation	Coal-Fired Generation Gross Capacity Factor
		Coal-Fired Generation Equivalent Availability Factor (EAF)
		Coal-Fired Generation Equivalent Forced Outage Rate (EFOR)
		Fuel Oil-Fired Generation Equivalent Availability Factor (EAF)
		Fuel Oil-Fired Generation Equivalent Forced Outage Rate (EFOR)
		Hydro Weighted Availability Factor (WAF)
		Hydro Weighted Forced Outage Rate (WFOR)
		Nuclear Collective Radiation Exposure (person mSv)
		Nuclear Forced Loss Rate (FLR) (%)
		Nuclear Performance Index
7	Reliability – Transmission & Distribution	Transmission 3-Year System Average Interruption Frequency Index (SAIFI)
		Transmission 3-Year System Average Interruption Duration Index (SAIDI)
		Distribution 3-Year System Average Interruption Frequency Index (SAIFI)
		Distribution 3-Year System Average Interruption Duration Index (SAIDI)

Quarterly Reports

NB Power has been preparing Quarterly Reports on its AMI strategy, as a result of a Board order from a previous case (Matter 271 Board Order dated April 9, 2015, paragraph 12). NB Power is proposing to continue to provide these Quarterly Reports, and is considering adding several key metrics to the report. These additional metrics include: percentage of network infrastructure installed; number of meters installed; percentage of data successfully communicated to the head end system; and percentage of customers billed from AMI data (NBP (PI) IR-48 (a)).

9.3. Conclusions

It is clear that NB Power has devoted considerable attention in recent years to performance metrics, in several forums and for several purposes. This effort provides a useful foundation for determining performance metrics that could be reported to the Board for informing rate case decisions.

In order to be useful for informing rate case decisions, utility performance metrics and reports should ideally (a) address priority performance areas in the rate case; (b) be provided at the outset of a rate case; (c) include timely information; (d) be accessible, reviewable, and easily understandable to all intervenors in the rate case; (e) provide lessons learned on what caused under-performance and how to improve future performance.

In general, the Company's current performance metrics and reports do not meet these criteria. First, the Company's current performance metrics do not some include some performance information relative to the rate case process. For example, the current KPIs do not include an indicator on rate case budgeting, and minimizing the differences between approved costs and actual costs.

Second, the Company's existing set of performance metrics were not provided in a comprehensive way at the outset of this rate case. Much of the information described in the previous section was obtained through discovery requests; the 2017/2018 CEP was obtained from the Company's previous rate case; and the 2016 Benchmarking report was obtained through a Google internet search.

Third, some of the information may not be very timely. The benchmarking report in particular uses data that are two years old by the time the report is released, due to the need to collect benchmarked data from peer utilities. The benchmarking report also presents the data as three-year rolling averages, which obscures more recent trends that might be important in a rate case.

Fourth, the information provided by the Company in this rate case on its current performance metrics cannot be described as accessible, reviewable, or easily understandable. It took a considerable amount of time for us to simply describe the existing performance metrics in the previous section, and we still have many questions regarding them. As noted in the previous section, there are many inconsistencies in the different ways that KPIs are reported, and it is not even clear whether all of the Company's KPIs are included in the discussion above.

Fifth, the performance reports that we reviewed provide little to no information regarding lessons learned on what caused under-performance or strategies being undertaken to improve future performance.

In sum, NB Power's current reporting is disjointed and incomplete, leaving regulators and intervenors with insufficient information with which to assess utility performance and inform ratemaking decisions. Below we provide recommendations for strengthening performance metrics going forward.

9.4. Recommendations

Rate Case Performance Reports

We recommend that the Board direct the Company to build off of its existing performance metrics and reports to create a Rate Case Performance Report, which would be filed in each rate case and used to inform the Board's decision in that case. These modifications include addressing additional performance areas; providing comprehensive information at the outset of a rate case; providing timely information; reporting the results in the most effective way; and discussing lessons learned.

Additional Performance Areas

The Rate Case Performance Reports should address several additional performance areas that are not currently reported. First and foremost, the Company should provide detailed information on its cost containment practices. This would include tables and charts showing the major variations between the Company's forecasted costs and its actual costs. The variations should be presented in enough detail by type of costs to prevent the Company from placing costs in one category to avoid over-runs in another. The report should present cost over-runs that exceed a certain threshold amount, along with the division and the division director responsible for the budgeting and the cost over-run. It should include data for the five most recent years, as well as for the most recent year. The quarterly cost and over-run data could be used to alert the Board to anticipated over-runs during the year.

The Company's performance metrics should also be expanded to present information relevant to the Company's Energy Smart programs. This should include a set of metrics for the energy efficiency and demand response programs in Smart Habits. It should include a set of metrics for AMI, if and when the Board allows the Company to proceed with an AMI project. Performance metrics can be especially important for innovative initiatives like AMI, because they can be used to monitor and encourage the achievement of the proposed benefits over time. The performance metrics should also include metrics related to the Smart Solutions programs and the development of the EV, distributed generation, and smart home technologies. They should also include metrics related to customer and third-party support services, such as distributed generation interconnection, third-party access, and provision of customer data.[24]

Presentation of Information

The Rate Case Performance Reports should be provided as part of each rate case filing. They should present the most important information in a way that is readily accessible and understandable. The Rate Case Performance Reports should be designed to primarily serve the needs of the Board, but also the needs of the NB Power Board of Directors, legislators, the Public Intervenor, customers, and other industry stakeholders.

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[24] For useful examples of such performance metrics, see Synapse, 2015, Tables 12 and 13.

The report should present historical data for the past five years, as well as performance targets for at least the next three years. Where available, the report should present a comparison of historical performance targets versus actual outcomes.

The Rate Case Performance Reports should use consistent terminology and structures, to facilitate understanding of how the KPIs are used by the Company and could be used by the Board. For example, this could include consistent categorization of KPIs across the key areas of excellence (safety, customer, organizational, reliability, and environmental).

NB Power should also provide the Rate Case Performance reports on a publicly accessible website with the most important data presented in graphs and tables that can be downloaded for independent analysis. The data in the website should be updated at least quarterly.

Timely Information

The Rate Case Performance Reports should include the most recent data available. Ideally, the Company would collect all the data related to its own performance on a quarterly basis. Quarterly data can be useful for providing guidance on performance during a year, and can also be useful at the end of the year to see any variations in the data by quarter. If the benchmarking data for other utilities takes longer to collect, then the peer reviews can wait until that data is made available; the reporting and assessment of the Company's own performance should not wait. Further, the data should not be aggregated into rolling averages, because this can mask results for specific years, including the most recent years.[25]

Lessons Learned

The Rate Case Performance Reports should provide discussion of the key lessons learned in the previous year and strategies for improvement going forward. This should include an explanation of cost variations, with an emphasis on significant cost over-runs. It should include a description of the Company's plans for addressing any over-runs, including better forecasting practices, productivity goals, and cost-containment practices. In each rate case the Board should identify those performance areas or cost types where the Company should provide more detailed lessons learned in the next year's rate case.

[25] The reports can present rolling averages if the Company finds them to be of use; as long as the annual information is provided as well.

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STATE OF RHODE ISLAND AND PROVIDENCE

PLANTATIONS PUBLIC UTILITIES COMMISSION

LEAST COST PROCUREMENT

STANDARDS JULY 28, 2017

CHAPTER 1 – Energy Efficiency Procurement

1.1. Introduction

A. Energy Efficiency (EE) Procurement, as mandated by §39-1-27.7, is intended to complement system reliability and supply procurement as provided for in §39-1-27.8, with the common purpose of meeting electrical and natural gas energy needs in Rhode Island in a manner that is optimally cost-effective, reliable, prudent, and environmentally responsible.

B. In order to adhere to the principles set forth in §39-1-27.7, and to meet Rhode Island's energy system needs in a least cost manner, the EE Standards set forth guidelines for the development of least cost energy efficiency plans.

1.2. Definitions

A. Energy Efficiency

i. Energy efficiency is defined as the reduction of energy consumption or strategic and beneficial management of the time of energy use within a defined system. A system may be a residence; a place of business; a public accommodation; or an energy production, delivery, and end-use consumption network.

ii. Energy Efficiency Plans should be designed, where possible, to complement the objectives of Rhode Island's energy efficiency; renewable energy; and clean energy programs, and describe their interaction with them, including, but not limited to, the System Reliability Procurement Plan; the Renewable Energy Standard; the Renewable Energy Growth Program; the Net Metering Program; and the Long-Term Contracting for Renewable Energy Standard. Energy Efficiency Plans should also be coordinated,